



DRAFT

**PERMIT TO OPERATE 9102 – R5
AND
PART 70 OPERATING PERMIT 9102**

**EXXONMOBIL – SYU PROJECT
PLATFORM HERITAGE**

**PARCEL OCS P-0182
SANTA YNEZ UNIT
SANTA BARBARA COUNTY, CA
OUTER CONTINENTAL SHELF**

OPERATOR

EXXONMOBIL PRODUCTION COMPANY (EXXONMOBIL)

OWNERSHIP

EXXONMOBIL PRODUCTION COMPANY (EXXONMOBIL)

**SANTA BARBARA COUNTY
AIR POLLUTION CONTROL DISTRICT**

JUNE 2012

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ABBREVIATIONS/ACRONYMS

acf	Actual Cubic Feet
APCO	Air Pollution Control Officer
AP-42	USEPA <i>Compilation of Emission Factors</i> document
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
ATC	Authority to Construct permit
BS&W	Basic sediment and water
bhp	brake horsepower
bpd	barrels per day (42 gallons per barrel)
BSFC	brake-specific fuel consumption
Btu	British thermal unit
CAAA	Clean Air Act Amendments of 1990
CAM	Compliance Assured Monitoring
CAP	Clean Air Plan
CARB	California Air Resources Board
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
clp	component-leakpath
CO	carbon monoxide
CO ₂	carbon dioxide
COA	corresponding offshore area
ERC	emission reduction credit
FHC	fugitive hydrocarbon
FR	Federal Register
gr	grain
g	gram
gal	gallon
HHV	higher heating value
H ₂ S	hydrogen sulfide
H&SC	California Health and Safety Code
IC	internal combustion
I&M	inspection and maintenance
k	thousand
kV	kilovolt
lb	pound
LFC	Las Flores Canyon
LHV	lower heating value
MCC	motor control center
MDEA	methyl diethanolamine
MM, mm	million
MMS	Minerals Management Service
MSDS	Material Safety Data Sheet
MW	molecular weight, Megawatts
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO _x	oxides of nitrogen (calculated as NO ₂)
NSPS	New Source Performance Standards
OCS	Outer Continental Shelf
PFD	process flow diagram
P&ID	piping and instrumentation diagram
POPCO	Pacific Offshore Pipeline Company

PTO	Permit to Operate permit
PTO Mod	Permit to Operate Modification permit
ppmv	parts per million volume (concentration)
ppmw	parts per million weight
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PM	particulate matter
PM ₁₀	particulate matter less than 10 μ m in size
PSV	pressure safety valve
PTE	potential to emit
PTO	Permit to Operate
PRD	pressure relief device
PVRV	pressure vacuum relief valve
ROC	reactive organic compounds
District	Santa Barbara County Air Pollution Control District or District or District
scf	standard cubic feet
scfd	standard cubic feet per day
scfm	standard cubic feet per minute
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SO _x	sulfur oxides
SYU	Santa Ynez Unit
TEG	triethylene glycol
TOC	total organic compounds
tpq	tons per quarter
tpy	tons per year
Trn O/O	transfer of owner/operator permit application
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency or EPA
UPS	uninterrupted power supply
VRS	vapor recovery system
wt %	weight percent

Fuel Types as listed in Section 5:

D2	Diesel
PG	Flare Purge and Pilot Gas
PR	Produced Gas
SG	Sales Gas

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1.0 Introduction

1.1. Purpose

General. The Santa Barbara County Air Pollution Control District (District) is responsible for implementing all applicable federal, state and local air pollution requirements which affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 55, 60, 61, 63, 68, 70 and 82. The State regulations may be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable local regulations can be found in the District's Rules and Regulations. This is a combined permitting action that covers both the renewal of the Federal Part 70 permit (*Part 70 Operating Permit 9102*) as well as the reevaluation of the State Operating Permit (*Permit to Operate 9102*).

The County is designated an ozone attainment area for federal ambient air quality standards and an ozone nonattainment area for state ambient air quality standards. The County is also designated a nonattainment area for the state PM₁₀ ambient air quality standard.

Part 70 Permitting. The initial Part 70 permit for Platform Heritage was issued January 11, 2000 in accordance with the requirements of the District's Part 70 operating permit program. This permit is the fourth renewal of the Part 70 permit, and may include additional applicable requirements. The District triennial permit reevaluation has been combined with this Part 70 Permit renewal, and this permit incorporates previous Part 70 revision (ATC/PTO) permits 9102 R2, ATC/PTO 11236. Platform Heritage is a part of the *ExxonMobil - Santa Ynez Unit (SYU) Project* stationary source (SSID = 1482), which is a major source for VOC¹, NO_x, CO, SO_x and PM₁₀. Conditions listed in this permit are based on federal, state or local rules and requirements. Sections 9.A, 9.B and 9.C of this permit are enforceable by the District, the USEPA and the public since these sections are federally enforceable under Part 70. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable. Conditions listed in Section 9.D are "District-only" enforceable.

Pursuant to the stated aims of Title V of the CAAA of 1990 (i.e., the Part 70 operating permit program), this permit has been designed to meet two objectives. First, compliance with all conditions in this permit would ensure compliance with all federally-enforceable requirements for the facility. Second, the permit would be a comprehensive document to be used as a reference by the permittee, the regulatory agencies and the public to assess compliance.

Tailoring Rule. This reevaluation incorporates greenhouse gas emission calculations for the stationary source. On January 20, 2011, the District revised Rule 1301 to include greenhouse gases (GHGs) that are "subject to regulation" in the definition of "Regulated Air Pollutants". District Part 70 operating permits are being updated to incorporate the revised definition.

¹ VOC as defined in Regulation XIII has the same meaning as reactive organic compounds as defined in Rule 102. The term ROC shall be used throughout the remainder of this document, but where used in the context of the Part 70 regulation, the reader shall interpret the term as VOC.

1.2. **Facility Overview**

- 1.2.1 **Facility Overview:** ExxonMobil Production Company (ExxonMobil), an unincorporated division of Exxon Mobil Corporation, is the sole owner and operator of Platform Heritage, located in the Santa Ynez Unit on lease tract P-0182 approximately 25 miles west of the City of Santa Barbara (Lambert Zone coordinates x = 783933 feet, y = 818088 feet). The platform is situated in the Southern Zone of Santa Barbara County. Figure 1-1 shows the relative location of Platform Heritage off of the Santa Barbara County coast. The platform is operated by ExxonMobil which has a 100-percent working interest ownership.

Platform Hondo is an eight-leg, 28 well slot platform that was installed in a water depth of 850 feet in 1976. Drilling operations began in 1977. Platform Hondo produces sour natural gas and crude oil. Average gravity of the produced crude oil is 18° API for Monterey emulsion and 37 API for sandstone emulsion. Emulsion and produced gas from Platform Hondo are shipped via sub-sea pipelines to onshore processing facilities in Las Flores Canyon approximately 20 miles west of Santa Barbara. Primary oil emulsion and gas separation takes place on Platform Hondo. The oil emulsion is shipped via a 14-inch pipeline to Platform Harmony where it combines with emulsion from Harmony and Heritage and then shipped to the Las Flores Canyon facility via a 20-inch sub-sea pipeline. The produced gas from Platform Hondo is dehydrated and compressed on the platform and shipped via a 12-inch pipeline to the POPCO gas plant in Las Flores Canyon. The design production rate for Platform Hondo is 75,000 barrels of oil emulsion per day and 85 million standard cubic feet of produced gas per day. Primary power for the platform is supplied through subsea power cables connected to ExxonMobil's onshore 49 MW cogeneration power plant at LFC.

The *ExxonMobil - SYU Project* stationary source consists of the following 5 facilities:

- | | |
|---------------------------------------|-------------|
| • Platform Harmony | (FID= 8018) |
| • Platform Heritage | (FID= 8019) |
| • Platform Hondo | (FID= 8009) |
| • Las Flores Canyon Oil and Gas Plant | (FID= 1482) |
| • POPCO Gas Plant | (FID= 3170) |



Figure 1.1 Location Map for Platform Heritage – Santa Ynez Unit Project (Onshore)

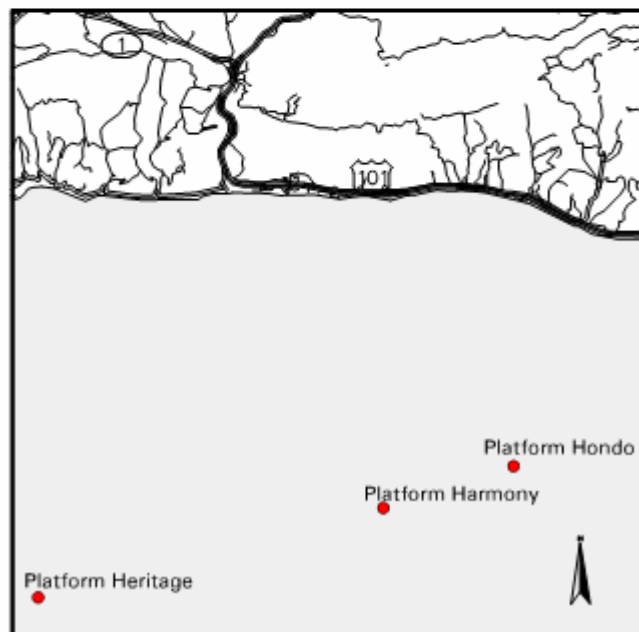


Figure 1.2 Location Map for Platform Heritage – Santa Ynez Unit Project (Offshore)

1.2.2 Facility Permitting History: The following is the permitting history for this facility:

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
ATC 09099	09/30/1993	See Permit
ATC Mod 09099 01	09/01/1994	See Permit
PTO 09102	09/04/1994	See Permit
PTO 09099	09/04/1994	See Permit
PTO Mod 09102 01	01/25/1995	Dedication of 20.68 tpy of SO _x ERCs to comply with Rule 359 requirements
PTO Mod 09102 02	05/02/1996	Added condition No. 34 (Crew and Supply Boat Stationary Source Maximum Permitted Emissions and Operational Limits). The purpose was to redefine the stationary source's annual potential to emit.
ATC 09634	12/18/1996	Approved the installation and operation of a shipping gas compressor (CZZ-306). BACT and offsets were required. ROC emissions increased by 0.59 tpy.
PTO 09634	11/12/1997	Slight reduction in emissions from ATC 9634 for compressor skid unit, due to revised component count and revised control efficiencies. ATC 9651-01 provides ERCs.
ATC 09828	01/21/1998	Authorizes installation of pig launcher and associated FHC components and safety relief and blowdown system. Topsides tie-in to Heritage Gas Pipeline Project. Offsets provided by ATC/PTO 9826. ROCs: 0.05 lb/hr, 1.31 lb/day, 0.06 tpq, 0.24 tpy.
ATC/PTO 10038	01/07/1999	Authorized changes included the revision of project emission factors, reduction of permitted solvent emissions, updated fugitive hydrocarbon leak path inventory, revised the stationary source crew and supply boat potential to emit downward and modified the allowable number of pigging operations. NO _x , ROC, CO, SO _x , PM and PM ₁₀ emissions decreased by 169 tpy, 60 tpy, 43 tpy, 38 tpy and 14 tpy respectively.
ATC/PTO 10169	09/21/1999	Authorized the use of larger crew and supply boats. Only short-term hourly and daily emissions increased. Through limitations of allowable fuel use, long term quarterly and annual emissions did not increase.
PT-70/Reeval 09102 R1	01/11/2000	Combined Reeval and Part 70 permit.
ATC 10182	06/08/2000	Phase II application to use larger crew and supply boats.
PTO 10348	12/13/2000	Temporary PTO for the use of the supply boat Santa Cruz for emergency maintenance of the buoy serving Platform Heritage. Also a Minor Part 70 Modification. See also PT-70 R 10372.
PT-70 R 10372	12/13/2000	Minor Part 70 Permit Modification. For temporary (14 days) use of the supply boat Santa Cruz to repair the Platform Heritage Buoy. See also District PTO 10348.

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
PTO Mod 09102 03	02/28/2001	Admin modification to replace the emergency IC engine permit condition to be consistent with Rule 202 requirements and the existing Platform Hondo permit. (see PT-70R 10396)
PTO 10182	04/23/2001	Permitting of larger supply boat (Santa Cruz, 4000 bhp) and crew boat (Callie Jean, 3800 bhp). Large increase in short-term PTE and no long-term PTE increase in ozone precursor pollutants.
ATC/PTO 10738	11/09/2001	Clarifies the allowable uses of crew and supply boats servicing Platform Heritage. Modifies the number of times the pig launchers/receivers can be used.
ATC/PTO 10800	05/20/2002	Reduces the amount of fuel that the crew boat main engines can use and increases the amount fuel that the crew boat auxiliary engines can use. Also, this permit clarifies for compliance purposes the dedicated project vessel and spot charter (combined) crew and supply boat main engine fuel use limits.
ATC/PTO 10993	05/19/2003	Allowed ExxonMobil to decrease their stationary source de minimis ROC emissions total by adding a portion to the stationary source NEI ROC total. The additional ROC NEI was offset by four ERC's generated due to various facility shutdowns.
PT-70/Reeval 09102 R2	05/19/2003	Triennial reevaluation of Part 70 PTO 9102 and consolidation of active permits.
ATC 11132	04/02/2004	High Pressure System Upgrade Project
ATC 11131	04/02/2004	Intermediate/Low Pressure System Upgrade Project
Exempt 11285	09/15/2004	Temporary Mooring Installation for Platforms Harmony, Heritage, and Hondo
ATC/PTO 11236	09/24/2004	Modifies the permitted supply boat engine profile to accommodate the M/V Pilot Tide as a project supply boat. In addition, new line items have been added for controlled auxiliary generator engines and uncontrolled auxiliary engines (winch). This permit also revises the fuel use limits in terms of "uncontrolled engine fuel use" and "controlled engine fuel use", rather than "main engines" and "auxiliary engines". This permit also modifies the recordkeeping requirements for unplanned flaring events by logging aggregate volume flared in place of logging individual unplanned events. ExxonMobil did not bring the M/V Pilot Tide to Santa Barbara County, so the Part 70/PTO 9102 R3 permit was only modified to include the winch engine on the M/V Santa Cruz.
PT-70 ADM 11334	10/26/2004	Change in responsible official from Sarah Ortwein to Hugh Thompson.
Exempt 11344	12/03/2004	Temporary equipment for HE Gas Expansion HP fireproofing project
Exempt 11343	12/03/2004	Temporary equipment for HE Gas Expansion HP blasting project
ATC Mod 11132 01	03/07/2005	Combined High Pressure and Intermediate/Low Pressure Gas Expansion Project

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
ATC Mod 11132 02	07/27/2005	Authorizes operation of the equipment installed under ATC 11132-01 and ATC 11132-02 for the Intermediate-Low Pressure Gas Expansion Project (IP/LP) and the High Pressure Gas Expansion Project (HP). This permit also includes an enhanced fugitive inspection and maintenance program as defined in ATC 11132-02.
PT-70 ADM 11770	08/23/2005	Change in responsible official from Hugh Thompson to Glenn Scott and Jon M. Gibbs
PTO 11132	09/30/2005	Operation of the HP and IP/LP gas installation permitted in ATC 11132 Mod-01. See PT-70 R 11356
PT-70/Reeval 09102 R3	05/22/2006	Triennial reevaluation of Part 70 PTO 9102 and consolidation of active permits.
PTO 11961	05/22/2006	Four diesel engines. Permitted due to loss of Rule 202 exemption. Limited to 200 hr/yr M&T operations. See Pt 70 R 11962
ATC 11986	05/23/2006	Authorizes the installation of new Tier II main propulsion and auxiliary diesel internal combustion engines on the <i>M/V Broadbill</i> crew boat. Also see DOI 0042
PTO 11986	08/16/2006	New Tier II main propulsion and auxiliary diesel internal combustion engines on the <i>M/V Broadbill</i> crew boat. Also see DOI 0042
PT-70 R 12121	09/25/2006	See PTO 11986
PT-70 ADM 12272	04/19/2007	Change in responsible official from Glenn Scott to James D. Siegfried.
PTO Mod 09102 04	07/10/2008	Cable C Repair Project near Platform Heritage. 25 day repair project with a specialized cable marine vessel.
ATC 13072	03/02/2009	Temporary installation and operation of a flare scrubber treatment system during turnaround activities to control emissions from depressurized vessels.
ATC/PTO 13491	10/6/2011	Incorporate fugitive hydrocarbon components associated with projects completed as de minimis.
PT-70 ADM 13746	8/25/2011	This administrative amendment changed the responsible official from Frank Betts to Troy Tranquada.
ATC 13818	2/28/2012	Temporary installation and operation of a flare scrubber treatment system during turnaround activities to control emissions from depressurized vessels.
PTO 13818	6/x/2012	Installation and operation of a flare scrubber treatment system during turnaround activities to control emissions from depressurized vessels.

1.3. **Emission Sources**

Air pollution emissions from Platform Heritage are the result of combustion sources, storage tanks and piping components, such as valves and flanges. Section 4 of the permit provides the District's engineering analysis of these emission sources. Section 5 of the permit describes the allowable emissions from each permitted emissions unit, the Platform as a whole, and also lists the potential emissions from non-permitted emission units.

The emission sources include the following:

- Crew, supply and emergency response boat engines

- Piping components (such as valves and flanges)
- Flare
- Helicopters
- Solvent cleaning
- Process heater
- IC engines

A list of all permitted equipment is provided in Section 10.4.

1.4. Emission Control Overview

Air quality emission controls are utilized on Platform Heritage for a number of emission units to reduce air pollution. Additionally, the use of onshore generated electricity from the 49 MW Cogeneration Power Plant at Las Flares Canyon allows Platform Heritage to operate without large gas turbine-powered generators or compressors. The emission controls employed on the platform include:

- An Inspection and Maintenance program for detecting and repairing leaks of hydrocarbons from piping components, consistent with the requirements of Rule 331, to reduce hydrocarbon emissions by approximately 80 percent.
- Use of turbo charging, enhanced inter-cooling and 4° timing retard on the crew and supply boat main engines to achieve a NO_x emissions rate of 8.4 g/bhp-hr or less.
- Installing an electric motor drive on one of the two crane engines.
- An amine unit on the platform removes sulfur from the fuel gas used on the platform thereby reducing SO_x emissions.

1.5. Offsets/Emission Reduction Credit Overview

- 1.5.1 Offsets: Prior to the issuance of PTO 9101 (9/4/94), ExxonMobil obtained ATC 9099 and ATC Modification 9099-1 for an amine fuel gas treating system. A ROC liability of 2.69 tpy was offset by securing 3.23 tpy of ERCs. Modifications permitted under ATC permits 9634 and 9828 required ROC offsets. Emission Reduction Credits (ERCs) in the amount of 0.67 tpy were secured for PTO 9634's offset liability of 0.56 tpy through PTO 9651 by the implementation of an enhanced I&M program at Las Flores Canyon. ERCs in the amount of 0.31 tpy were secured for ATC 9828's offset liability of 0.26 tpy through ERC Certificate No. 0004-0103 by the implementation of an enhanced I&M program at Las Flores Canyon. The ROC offset requirements are detailed in Table 7.1.

Under PTO 9102-01, ExxonMobil secured 20.68 tpy of SO_x ERCs for Platform Heritage. These ERCs were created due to the shutdown of the OS&T vessel. The ERCs are required pursuant to Rule 359, from which ExxonMobil obtained an exemption from the planned flaring sulfur content standard of 239 ppmv.

- 1.5.2 Emission Reduction Credits: Per DOI 0039 Platform Heritage generated 0.115 TPQ ROC (0.459 TPY) due to the implementation of an enhanced fugitive inspection and maintenance program permitted under ATC 11132 Mod -01.

Emission Reduction Credits: Under DOI 042-01 ExxonMobil generated 1.843 tpq NO_x and 0.072 tpq PM/PM₁₀ due to the replacement of the diesel main propulsion and auxiliary engines on the dedicated crew boat for the Exxon – SYU project, the *M/V Broadbill* as permitted under ATC/PTO 11986.

1.6. Part 70 Operating Permit Overview

- 1.6.1 Federally-Enforceable Requirements: All federally enforceable requirements are listed in 40 CFR Part 70.2 (*Definitions*) under “applicable requirements.” These include all SIP-approved District Rules, all conditions in the District-issued Authority to Construct permits, and all conditions applicable to major sources under federally promulgated rules and regulations. All permits (and conditions therein) issued pursuant to the OCS Air Regulation are federally enforceable. All these requirements are enforceable by the public under CAAA. (*see Tables 3.1 and 3.2 for a list of federally enforceable requirements*)
- 1.6.2 Insignificant Emissions Units: Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit’s potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit’s potential to emit. Insignificant activities must be listed in the Part 70 application with supporting calculations. Applicable requirements may apply to insignificant units. See Attachment 10.4 for a list of Part 70 insignificant units.
- 1.6.3 Federal Potential to Emit: The federal potential to emit (PTE) of a stationary source does not include fugitive emissions of any pollutant, unless the source is: (1) subject to a federal NSPS/NESHAP requirement which was in effect as of August 7, 1980, or (2) included in the 29-category source list specified in 40 CFR 51.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. (*See Section 5.4 for the federal PTE for this source*)
- 1.6.4 Permit Shield: The operator of a major source may be granted a shield: (a) specifically stipulating any federally-enforceable conditions that are no longer applicable to the source and (b) stating the reasons for such non-applicability. The permit shield must be based on a request from the source and its detailed review by the District. Permit shields cannot be indiscriminately granted with respect to all federal requirements. Although ExxonMobil made a request for a permit shield, no permit shields were granted to ExxonMobil due to the broadness of the request.
- 1.6.5 Alternate Operating Scenarios: A major source may be permitted to operate under different operating scenarios, if appropriate descriptions of such scenarios are included in its Part 70 permit application and if such operations are allowed under federally-enforceable rules. ExxonMobil made no request for permitted alternative operating scenarios.

ExxonMobil lists their main operating scenario as: “Platform Heritage is an oil and gas production platform (SIC 1311). Its main products are crude emulsion and gas. The platform also produces byproducts from crude oil and gas production operations. Normal facility operations include periods of startup, shutdown and turnaround. Periodically, malfunctions may occur.”

- 1.6.6 Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally-enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application; and, be re-submitted annually on or before March 1st or on a more frequent schedule specified in the permit. Each certification is signed by a “responsible official” of the owner/operator company whose name and address is listed prominently in the Part 70 permit.
- 1.6.7 Permit Reopening: Part 70 permits are re-opened and revised if the source becomes subject to a new rule or new permit conditions are necessary to ensure compliance with existing rules. The permits are also re-opened if they contain a material mistake or the emission limitations or other conditions are based on inaccurate permit application data. This permit is expected to be re-opened in the future to address new monitoring rules, if the permit is revised significantly prior to its first expiration date. (*see Section 4.11.3, CAM Rule*).
- 1.6.8 Hazardous Air Pollutants (HAPs): Being an OCS source, the requirements of Part 70 permits also regulate emission of HAPs from major sources through the imposition of maximum achievable control technology (MACT), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any other rule applicability.
- 1.6.9 Responsible Official: The designated responsible official and their mailing address is:

Mr. Troy Tranquada (SYU Operations Superintendent)
ExxonMobil Production Company
(a division of Exxon Mobil Corporation)
12000 Calle Real
Goleta, CA 93117

Telephone: (805) 961-4078

and

Mr. James D. Siegfried (Operations Manager)
ExxonMobil Production Company
(a division of Exxon Mobil Corporation)
396 West Greens Road
Houston, TX 77067

Telephone: (713) 431-2047

2.0 Process Description

2.1. Process Summary

Platform Heritage produces sour (with H₂S) crude oil (oil/water emulsion) and gas. The design rate for the platform is 75 bopd of oil emulsion and 75 MMscfd of produced gas containing up to 30,000 ppmv H₂S. The platform production equipment includes wells, pressure vessels, shipping pumps, transfer pumps, gas and refrigerant compressors, tanks, a glycol contactor and regenerator, a depropanizer, an amine contactor and still, a process heater, sumps, heat exchangers and coolers and pipeline pigging equipment. No separation of the produced oil and water emulsion takes place onboard the platform. All produced liquids are shipped to Platform Harmony and then onto ExxonMobil's Las Flores Canyon facility for dehydration via a 20-inch subsea pipeline. Produced gas containing H₂S is separated from the produced liquids in the platform's gas/liquid separators and scrubbers. The gas on the platform is then compressed, dehydrated and refrigerated to remove heavy ends. The resulting gas can be combusted as fuel or compressed for re-injection or gas lift gas. No gas pipeline exists to transfer sales gas to the onshore gas plant. The current daily production rate is approximately 55,000 barrels of oil emulsion and 40 MMscf of gas.

The Monterey production flows to either the low pressure (LP) system or the intermediate pressure (IP) system based on Tubing Flowing Pressure and Gas Oil Ratio. The IP suction scrubber knocks out additional liquids prior to compression. The compressors accommodate three operating systems: LP (70 psig), IP (140 psig), and sandstone (350 psig). Due to Gas Injection Compressors (IGC) compression constraints (72 MSCFD), gas sales can be increased from Heritage platform to maintain POPCO loading.

The water injection capacity of 14 KBWD is used to maintain reservoir voidage/pressure. A water injection pump and expanded chemical injection skid are used to mitigate risk of downhole corrosion, bacterial formation, and scale build up.

The equipment installed for the IP/LP project connects to the existing drain, vent and flare systems on the platform as well as necessary utilities. For waste gas flaring, the operation of the meters on the main line has a range from 0.068 MMscfd to 125 MMscfd.

Gas is piped from the Sandstone production header through the High Pressure Production Header to either the HP Production Separator or the HP Test Separator. These separators operate at the flowing pressure of approximately 1,100 psig. The two separators function in the same manner as the existing Monterey separators except for the higher operating pressure. Production going to the HP Test Separator can also pass through the HP production exchanger, which uses hot oil as the heating medium to prevent hydrate formation. This heater will normally only be required during the initial start-up of the system. The HP Test Separator also contains a meter to determine the volume of the gas and emulsion production for accounting purposes. The liquid from the HP Test Separator will be transferred to the lower pressure Sandstone Test Separator for metering of the liquid and associated gas.

Saturated HP gas from the HP production and test separators are combined and sent to a HP Production Scrubber. The separator serves the purpose of removing any liquids in the gas prior

to compression. The outlet gas from the separator is commingled with the existing dehydrated compressed gas at the suction to the Gas Injection Compressors (IGCs). The IP/LP project added a fuel gas tie-in prior to the separator to allow use of the low H₂S gas for platform fuel use. The tie-in to the new separator is downstream of the branch from the platform sales gas pipeline. The HP non-dehydrated gas does not enter the sales gas pipeline. Associated HP system liquids from the separators are commingled with existing Sandstone production at the Sandstone Production Separator (MBD-108). The liquids flow to the Sandstone Flash Separator (MBD-122) are either used as diluent or transferred to the Emulsion Surge Tank (MBD-110).

The recycle for the IGCs are routed to the new IGC suction scrubber to prevent wet gas from the IGCs from entering the sales gas pipeline. The system is designed for sour service due to the presence of sour gas from the IGC recycle stream. The take off for the recycle is downstream of the IGC Discharge Coolers (HBG-246/247), to allow the recycle gas to be cooled.

The High Pressure production system is designed for sour service excluding the well flow lines. Sour gas is expected to enter the HP production system downstream of the HP Production and Test Separators due to a modification to the IGC recycle flow. The platform operational flaring will not significantly change as a result of the project.

- 2.1.1 Production: The platform has 60 well slots. There are presently 47 well completions onboard the platform. Of the 47 completions, 42 are producing oil and gas (one well has dual completions of which one of the completions are currently producing with the other shut-in), three wells are used as a gas cap gas injection wells, and two are used as disposal wells. At this time, three of the wells are flowing, producing oil and gas without the aid of artificial recovery methods. The remaining 40 wells are produced by means of gas lift recovery.

The well bay contains four production manifolds and one gas injection manifold. Each production manifold contains the following headers:

- Monterey Production Header which sends the produced emulsion and gas from the wells to one of two Monterey Production Separators.
- Sandstone Production Header which sends produced emulsion and gas from the Sandstone and associated gas wells to the Sandstone Production Separator.
- High Pressure Production Header which was installed to connect to a potential future High Pressure Production Separator

HP Production Facilities System:

- *HP Manifolds* – Four (4) of the HP manifold slots are sized for maximum design flow rates of 20 MSCFD and 2,800 BLPD. Three (3) of the remaining HP manifold slots are sized for maximum design flow rates of 15 MSCFD and 2,800 BLPD. The three (3) HP manifold slots are tied to existing Sandstone wells are designed using 3" line size. The slots are used for 5,000-psig service equipment.
- *HP Production Header* – The HP Production Header is sized for maximum design flow rates of 60 MSCFD and 8,400 BLPD.

- *HP Production Separator* – Gas and liquid separation of the full well stream production from the high pressure wells occur in a horizontal, two-phase separator with a design capacity for 60 MSCFD and 8,400 BPD liquids at 1,155 psig. The separator provides two (2) minutes of retention time. The gas is metered out of the separator. A connection to the fuel gas system is taken off downstream to supply a design rate of 500 KSCFD to the fuel gas scrubber, MBF-120.
- *Gas Injection Compressor Scrubber* – Gas from the HP separators is commingled with the IGC recycle gas upstream of being scrubbed in a vertical, two-phase separator with a design capacity for 75 MSCFD and 1,500 BPD liquids at 1,140 psig. The scrubber is sized to provide 2 minutes of retention time. The gas from the scrubber flows to the IGC suction lines, with the tie-in downstream of the branch for gas to the sales pipeline.
- Monterey Test Header which sends the produced emulsion and gas from a well to one of two Monterey Test Separators.
- Sandstone Test Header which sends the produced emulsion and gas from one of the Sandstone or associated gas wells to the Sandstone Test Separator.
- High Pressure Test Header which was installed to connect to a potential future High Pressure Test Separator

HP Test Facilities System:

- *HP Test Manifold* – Four (4) of the HP test manifold slots are sized for maximum design flow rates of 20 MSCFD and 2,800 BLPD. Three (3) of the remaining HP test manifold slots are sized for maximum design flow rates of 15 MSCFD and 2,800 BLPD. The three (3) HP test manifold slots that are tied to existing Sandstone wells are designed using 3" line size. Design is for 5,000-psig service equipment.
- *HP Test Header* – The HP Test Header is sized for maximum design flow rates of 20 MSCFD and 2,800 BLPD.
- *Start-Up Heat Exchanger* – A start-up gas heat exchanger is installed in the HP Test Header to assist with hydrate prevention when bringing on high flowing tubing pressure wells. There is a bypass around the exchanger for normal well testing. A choke is installed downstream of the exchanger. The exchanger is designed for 5,000-psig service. The heater has sufficient duty to heat 5 MSCFD of gas and 700 BPD of liquids from 50 °F to 112 °F, which is sufficient to maintain a temperature of 60 °F on the downstream production choke valve outlet. The platform hot oil system is the heat source for the exchanger.
- *HP Test Separator* – Gas and liquid separation for testing of the full well stream production from the high-pressure wells occurs in a horizontal, two-phase separator with a design capacity for 20 MSCFD and 2,800 BPD liquids at 1,155 psig. The separator provides 3 minutes of retention time. The gas production out of the HP test separator is metered. The liquid production is transferred to the Sandstone Test Separator for measurement of liquid and associated gas.

- *Production Manifolds* – The existing 6” future HP Production Header logs in production manifolds ZZZ-541, ZZZ-543 and ZZZ-544 are used for IP service. Both ends of the logs on manifolds ZZZ-541 and ZZZ-544 are connected to a new 14” IP Production Header.
- *IP Production Header* – A 14” IP Production Header flows the maximum design flow rates of 45 MSCFD and 17,000 BLPD @ 140 psig.
- Gas Lift Header which supplies each well with dehydrated and conditioned produced gas for gas lift.
- Chemical Batch Treatment Header which is used to periodically inject batch chemicals down a well.
- Well Cleanup Header which sends the produced emulsion and gas following an initial completion or a well workover to the Well Cleanup Separator.

The gas injection manifold is connected to up to three wells and supplies dehydrated and conditioned produced gas to the well for re-injection or back into the formation.

- 2.1.2 Gas/Emulsion Separation: All separators located on the platform are two phase (i.e., gas and liquid). Capacities of separators are as follows:

IP/LP Production, Separation, Compression, and Water Injection Systems:

- *IP Wells* – Seven existing wells are directed to the IP system (HE-1, -3, -4, -7, -9, -10, and -12).
- *IP Flow lines* – High flow rate IP wells HE-1, -3, -4, -7 and -10 require dual 4” or single 6”x4” flow lines to achieve 200 psig flowing tubing pressure. HE-1 and HE-4 flow lines have 4” branch connection tees; HE-3, HE-7 and HE-10 do not. Five additional manifold slots are utilized to dual these flow lines. HE-1 and HE-7 also has flow line choke changes installed.
- Monterey Production Separator (MBD-102): 50 kbpd emulsion; 40 MMscfd gas.
- *IP Production Separator* (MBD – 101): Monterey Production Separator MBD-101 is rated for pressure from 144 psig to 164 psig MAWP in accordance with API-510 and ASME Section VIII, Division 1.
- Monterey Test Separator (MBD- 104): 7.5 kbpd emulsion; 7.5 MMscfd gas.
- *IP Test Separator* – Monterey Test Separator MBD-103 is rated for pressure from 158 psig to 183 psig MAWP in accordance with API-510 and ASME Section VIII, Division 1.
- Sandstone Separator (MBD-108): 10 kbpd emulsion; 15 MMscfd gas

- Sandstone Test Separator (MBD-112): 2 kbpd emulsion; 6 MMscfd gas
- Well Cleanup Separator (MBD-113): 5 kbpd emulsion, 5 MMscfd gas.
- *IP Suction Scrubber* (MBF – 109): Gas from the IP Production and Test Separators is commingled with IP compressor recycle gas and flow to the IP Suction Scrubber (approximate dimensions of 54" ID x 12' S/S, 220 psig MAWP @ 325°F). The suction scrubber, MBF-109, is located on the cellar deck extension installed on the north side between truss rows 3 and 4. The deck extension is shared with the HP IGC Gas Suction Scrubber.
- *Water Injection* – The seawater Injection capacity is 14,000 BWPD. A 100± HP electric seawater injection pump boosts 10,000 BWPD from 50 to 500 psig for wells HE-21 and HE-26. A spare 100 HP motor from the pilot seawater injection pump may be used, if available. Plans are to continue injecting 4,000 BWPD into HE-13 from the 50-psig seawater source without boost to 500 psig.

All emulsion is routed to the Emulsion Surge Tank (MBJ-110). Sour gas is routed to the First Stage Suction Scrubber (MBF-114) where it is then compressed, dehydrated and conditioned and then further compressed for gas injection or gas lift. A side stream of conditioned sour gas is routed to the fuel gas treating unit where the gas is contacted with an amine solution to remove hydrogen sulfide. This sweet gas is then scrubbed and filtered prior to entering the platform fuel gas header.

There are four types of drain systems on the platform: Closed Drain, Deck/Open Drain, Glycol Drain and Amine Drain. The Closed Drain system collects hydrocarbon contaminated drainage from all of the process vessels, equipment and manifolds as well as selected skid and deck drains that have a high potential to contain hydrocarbons and/or chemicals. The liquids collect in the Closed Drain Sump (MBH-132) from where it is transferred by one of two pumps (PBH 363 or 364) to the Emulsion Surge Tank.

In general, the Deck/Open Drain System collects all production deck and cellar deck surface drainage as well as liquids from non-hydrocarbon atmospheric drains. All of the decks have kick plates which are seal welded around deck penetrations and the perimeter to prevent any fluids from spilling over. Any liquid spilled on the deck will collect in the deck drains and will then flow to the Open Drain Sump (ABH-406). Any hydrocarbons that may be present, however, are skimmed from the Open Drain sump and pumped to the Closed Drain System for eventual disposal in the oil production system, while water from the Open Drain Sump gravity flows to the Skim Pile for release to the ocean. The drilling deck drains are handled by a separate drain system tied to the Drill Deck Drain Settling Tank (ABJ-417) to prevent contamination of the oil production system. The solids settling tank separates the solids (drilling additives/solids and mud) from the liquids for disposal to the disposal caisson. The separated liquids flow by gravity to both the Open Drain Sump and the Skim Pile. The wellbay area has a separate sump (ABH-405) to collect surface drainage from the wellbay area. This drainage is pumped to the Drill Deck Drain Settling Tank.

The Glycol Drain System is a closed system which collects drainage from the Glycol Regeneration System equipment, the glycol contactor, and the Depropanizer Reboiler. The

glycol drainage flows from a collection header to a sump from which it is pumped, filtered and returned to the Glycol Regeneration System. The Glycol Drain Sump is also used as a means for adding glycol makeup from tote tanks to the system.

The Amine Drain System is a closed system which collects drainage from the Amine Regeneration equipment and the Fuel Gas Scrubber (MBF-120). The amine drainage flows through a collection header to a sump from which it is pumped, filtered, and returned to the Amine Regeneration System. The Amine Sump is also used as means for adding amine make-up from tote tanks to the system.

- 2.1.3 Waste Water Treatment: There are no waste water treatment facilities that remove produced water from the oil on this platform.
- 2.1.4 Well Testing and Maintenance: In order to measure individual well production rates, production is directed to one of three test separators. The production test facilities allow for remote testing of any well. Liquids exiting the test separators flow to the Emulsion Surge Tank while sour gas is routed to the First Stage Suction Scrubber.

After a well workover is completed, the oil production from the well is started by producing the well to either a test separator or the Well Cleanup Separator (MBD-113). This segregates the well from the rest of the producing wells. Producing the well into a test separator prevents upsetting the normal production on the platform should the new well have unanticipated flow surges. Producing the well into the Well Cleanup Separator allows the lowering of the tubing pressure to a level which will facilitate flow. Additionally, it will prevent the separators from being contaminated with material left in the well from the workover. This tank is equipped with a washout jet header system and ram-type drain valves to assist in solids removal. Following treatment in the Well Cleanup Separator, emulsion is routed to the Emulsion Surge Tank and gas to the First Stage Suction Scrubber.

- 2.1.5 Emulsion Breaking and Crude Oil Storage: Produced fluids are in the form of a tight oil/water emulsion which can be broken through the use of chemicals. Demulsifying chemicals can be injected both downhole and in the surface facilities, if required.

The Emulsion Surge Tank collect liquids from the two Monterey Test Separators, the two Monterey Production Separators, the Sandstone Production Separator, the Sandstone Test Separator, the STV Compression Suction Scrubber, the First Stage Suction Scrubber, the Well Cleanup Separator, the Amine Reflux Accumulator, the Glycol Hydrocarbon Separator and the Closed Drain Sump.

- 2.1.6 Crude Oil Shipping: Liquids are shipped from the Emulsion Surge Tank to Platform Harmony and then to Las Flores Canyon via a 20" subsea pipeline using one or more of the positive displacement screw type Emulsion Shipping Pumps (PAX-331, 332, 333) operated simultaneously to provide the desired flow capacity.

The pumps take suction from the Emulsion Surge Tank and pump the emulsion to pipeline discharge pressure which may vary from a few hundred psi to over 1000 psi, depending on throughput and emulsion properties. The liquid from the pumps is combined with recovered heavy ends from the conditioning unit (depropanizer) prior to being metered and sampled in the emulsion shipping ACT unit (ZAU-518) for production allocation and leak detection. This stream then

enters the emulsion pipeline that contains a pig launcher on the platform. When a pig is being launched, the flow is directed through the emulsion pig launcher (KAH-791).

- 2.1.7 Gas Compression, Dehydration and Conditioning: The produced gas system is designed to collect and compress virtually all produced hydrocarbon vapors, dehydrate the compressed gas to a dew point of -40°F , refrigerate the gas to recover propane and heavier hydrocarbon liquids, and sweeten a slip stream of gas prior to distribution as either sales and/or transport gas, gas lift gas, re-injection gas or platform fuel gas.

There are five stages of compression; Vent Recovery Compression, Surge Tank Vapor (STV) Compression, First Stage Main Gas Compression, Second Stage Main Gas Compression, and Gas Injection Compression. The first stage of compression, the Vent Recovery Compressor, takes gas at essentially atmospheric pressure and compresses it to an intermediate pressure of 15 psig. Other intermediate or interstage pressures are 72 psig (STV Discharge), 325 psig (First Stage Discharge), 1100 psig (Second Stage Discharge), and 2976 psig (Gas Injection Discharge). All compressors are electric motor driven reciprocating machines totaling 13800 hp (17300 hp in the future).

- Vent Recovery Compressor: A single Vent Recovery Compressor compresses all vapors from the 1 psig vent recovery header and the glycol regenerator. This compressor is a 50 hp rotary vane type with a discharge pressure of approximately 15 psig and a capacity of 0.5 MMscfd.
- Surge Tank Vapor (STV) Compressors: Two 100% STV Compressors compress the 15 psig gas from the emulsion surge tank, the gas from the vapor recovery compressor, and the acid gas from the amine regenerator to a discharge pressure of approximately 72 psig. The compressors are balanced opposed, two cylinder, single stage 900 RPM, 250 hp with a capacity of 1.04 MMscfd each. The STV compressor system includes two inlet coolers and a common suction scrubber.
- First and Second Stage - Main Gas Compressors: Four 25% First and Second Stage Main Compressors are provided. These compressors are six throw balanced opposed 900 RPM reciprocating type machines rated at 3500 hp each. Four cylinders (throws 3 through 6) serve as the "First Stage" Main Gas Compressor while the remaining two cylinders (throws 1 and 2) serve as the "Second Stage" Main Gas Compressor.
 - The First Stage of compression takes suction from the production separators and the STV compressors at approximately 72 psig and compresses the gas to a discharge pressure of approximately 325 psig in two stages without intercooling. Cylinders 4 and 6 compress the gas from 72 psig to approximately 175 psig while cylinders 3 and 5 compress the gas from 170 psig to 325 psig. The First Stage Main Gas Compressors are equipped with dual inlet coolers with a common suction scrubber and with dual outlet coolers with a common discharge scrubber. The total capacity of the first stage system is approximately 75 MMscfd. The compressed gas is conditioned by dehydration and refrigerated for heavy ends removal prior to returning to the Second Stage Main Gas Compressors.

- The Second Stage Main Gas Compressors compress the treated gas stream from 300 psig to 1100 psig in two stages without intercooling. The first stage of compression (cylinder 1) discharges at approximately 630 psig while the second stage (cylinder 2) discharges at 1100 psig. The Second Stage Main Gas Compressors are equipped with a common suction scrubber and dual outlet coolers with a common discharge scrubber. The total capacity of the second stage compression is approximately 51 MMscfd (68 MMscfd with future unit addition). The high pressure gas from this system supplies the platform gas lift system, gas sales and/or transport (future) and the gas injection system.
- *IP Compressors* – Two of the MGC's (CZZ-304 and CZZ-305) had three of the six throws re-cylindered and converted to IP suction and Sandstone sidestream service in the IP/LP project. IP compressor cylinders are 15.75" (2), 10.5" (2) and 9.5" (1). The 10.5" and 9.5" cylinders are new; the 15.75" cylinders were re-used. The modification increased the capacities of these two machines from 18 MSCFD at 70 psig to 24 MSCFD at 130 psig. The existing 3500 HP motors have sufficient power for IP service modifications. Four 11.5", two 11" and two 8.5" existing cylinders are now spares. The new 10.5" and 9.5" cylinders allow the compression horsepower to be loaded with 38 MSCFD of sidestream (Sandstone) gas. The cylinders may be equipped with variable volume pockets. As a minimum, new pulsation bottles will be required for the new 10.5" and 9.5" cylinders.
- *LP Compressors* – Two of the MGCs (CZZ-303 and CZZ-306) remain in LP service. CZZ-303 has been upgraded from 3,500 HP to 5,400 HP and has a new 4160 V, 5,000 HP electric motor installed. A 5,000 HP motor starter is in the MCC lineup in Module BU building. CZZ-303 has new 20" (2), 18" (1), 10.5" (2) and 9" (1) cylinders, increasing the capacity of CZZ-303 from 18 MSCFD to 27 MSCFD of 70-psig gas. The cylinders may be equipped with variable volume pockets. Two 15.75", two 11.5", one 11" and one 8.5" cylinders will become spares. New pulsation bottles will be installed on all stages.
 - Main gas compressor CZZ-306 were not be modified; its capacity will remain at 18 MSCFD of 70 psig gas with existing cylinders 16"(2), 11.5"(2), 11"(1) and 8.5"(1).
 - Cooper has globally re-rated their Superior W76 frame to 5,400 HP provided all six throws are cylindered. With 60 psig, 80°F suction gas, the 2nd stage discharge temperatures of the LP compressors will increase from 290°F to 300-305°F. In the event the Main Gas Compressors are running when depropanization is down, 4th stage discharge temperatures will increase from 250°F to 295°F at 1200 psig discharge pressure.
- *Gas Injection Compressors*: The Gas Injection Compressors consist of two 50% four cylinder, balanced opposed reciprocating type 900 RPM compressors rated at 1500 hp each. Gas is compressed from 1100 psig to approximately 2976 psig in a single stage of compression. The total capacity of the injection compressors is 55 MMscfd. The high pressure gas from this system supplies the platform gas lift system as well as the gas injection system.
 - Gas from the main gas compressor first stage is conditioned by routing the compressed gas through a TEG contactor for dehydration followed by a depropanizer to remove

recoverable propane and heavier hydrocarbons. NGL's recovered in the gas conditioning process are routed to the emulsion pipeline.

2.1.8 Dehydration and Glycol Regeneration: A standard TEG contactor dehydrates saturated gas from the Main Gas Compressor First Stage Discharge Scrubber to a design water dew point of minus 40 °F. A filter upstream of the TEG Contactor helps control carryover of heavy hydrocarbons and particulates into the Contactor. Rich TEG from the Contactor is regenerated in the Glycol Still by heating the glycol solution to approximately 400 °F with heating oil and stripping with a small amount of fuel gas. Lean TEG from the regenerator reboiler is cooled and pumped back to the Contactor for dehydration of the gas stream. A sidestream of lean glycol is continuously recycled through a charcoal filter to remove hydrocarbons.

2.1.9 Depropanizer: The Depropanizer recovers propane and heavier natural gas liquids (NGLs) from the dehydrated gas by cold temperature separation and fractionation. The dehydrated gas from the TEG Contactor is cooled in the Gas/Gas Exchanger and combined with the Depropanizer overhead vapor prior to further cooling in the Depropanizer Condenser. The Depropanizer operates as a conventional fractionator with a bottoms reboiler and refrigerated overhead partial condenser. The Depropanizer bottoms product is subcooled and pumped to emulsion pipeline pressure before commingling with the crude emulsion. Reflux for the Depropanizer is generated by chilling the rich gas from the Gas/Gas Exchanger and Depropanizer overhead vapor in the Depropanizer Condenser. The conditioned gas leaving the Depropanizer Reflux Accumulator is heat exchanged with the dehydrated rich gas in the Gas/Gas Exchanger and then flows to the second stage of the Main Gas Compressors.

2.1.10 Gas Sweetening and Sulfur Recovery: The platform contains a gas sweetening unit to produce fuel gas for use on the platform. There is no sulfur recovery system on the platform.

Sweet fuel gas for the platform is produced from sour conditioned gas drawn off at the suction of the second stage of the Main Gas Compressors. The gas is sweetened in an Amine Contactor by countercurrent contacting with MDEA (Amine) solution to selectively remove H₂S. The sweetened gas is scrubbed and heated to 100 °F and routed to the fuel gas system. The acid gas removed in the amine regeneration system is recycled to the STV compressor.

2.1.11 Vapor Recovery System: All vessels and tanks on the platform with the exception of nine atmospheric vessels (mainly chemical and lube storage) and three sumps (Open Drain, Skim Pile and Wellbay) are connected to either the gas gathering, vapor recovery or the flare header systems.

Vessels that operate at pressures above 50 psig relieve excess pressure through the PSVs to the flare header. The remaining vessels and tanks that are connected to one of the recovery systems normally relieve through a PSV or vent directly to one of the vapor recovery systems that recycle gas to the platform gas compression system. The pressure relief valves only open during emergency situations or mandatory testing.

2.1.12 Heating and Refrigeration: The platform contains a recirculating hot oil system heated by a direct fired process heater and a mechanical refrigeration system that utilizes refrigerant compressors.

The Heating Oil System provides a heat source for the Glycol Regeneration Reboiler, the Amine Regeneration Reboiler, the Depropanizer Reboiler, Well Cleanup Separator, Closed Drain Sump, Monterey Production Heater and the Non-Associated Gas Well Stream Heater. The system con-

sists of a heating oil surge tank, circulating pumps, supply and return headers, and a direct fired process heater. The system transfers heat from the heater to the process exchangers by circulating a heating media (ExxonMobil Caloria HT43).

A closed cycle mechanical refrigeration system is used to cool and partially condense vapors in the Depropanizer and Glycol Contactor overhead. Process side temperatures range from minus 15 °F to minus 30 °F. The refrigeration system is designed for a minimum refrigerant evaporator temperature of minus 40 °F.

2.1.13 IP/LP Utility Systems:

- *Electrical Power:* A 4160V, 5,000 HP synchronous motor starter have been added to the MCC lineup in building BU. No other additional electrical loads are anticipated.
- *Instrument Air:* Several new small users (SDV's and a BDV) have been added to the system. The platform system has adequate capacity to handle the additional loads.

2.1.14 Waste Gas Flaring:

- *Flare System Design:* The Flare System is made up of the flare headers, a flare scrubber, a flare tip and an ignitor panel. The flare system collects the discharged fluids from all equipment relief valves, emergency back pressure control valves, and manual blowdown valves. The flare scrubber separates any liquid from the gas prior to burning at the flare tip. The separated liquid is automatically dumped into the closed drain system. Three constantly burning pilots evenly spaced around the flare tip provide a continuous ignition source for the discharged gases in all wind conditions.

Pressure relief devices are installed, as required by industry code design specifications, on all applicable pressure vessels, tanks, sumps, compressors, pumps, piping systems, pipelines and other designated components.

The flare measuring system on the platform consists of four separate flow meters to determine the volume of gas sent to the flare. The main line to the flare contains a high flow (FE-134-1) and low flow (FE 134-2) meter. The separate vent recovery system relief to the flare contains a low flow (FE 134-3) meter as well as low flow (FE 134-4) meter measuring the flow rate from the auxiliary distance pieces. The range of operations of the meters on the main line is from a maximum of 125 MMscfd to a minimum of 0.068 MMscfd while the vent recovery relief meter has a range of 0.56 to 0.001 MMscfd.

- *IP/LP Flare Tip* – Approximately a 49 psig pressure drop occurs across the existing Zink (Kaldair) Indair tip at a flow of approximately 125 MSCFD. The existing 40 psig rating of the tip bypass burst plate was increased to avoid nuisance replacements. The design of the existing flare tip provides a stable flame at all flow rates.
- *Meter* – The operation of the meters on the main line have a range from 0.068 MSCFD to 125 MSCFD.

- *Planned Flaring Scenarios:* Planned flaring events include, but are not limited to the following: pipeline blowdown, platform turnaround, OEM safety tests, planned equipment shutdown and startup, well cleanup/blowdown and valve leakage. The four most common or routine planned flaring scenarios that occur on the platform are described below:
 - (1) During startup of specific units (i.e., the compression system), a manual purge may be performed to remove air from the system. This minimizes the possibility of having combustible gas mixtures in the process. This purge is performed with sweet fuel gas.
 - (2) During the shutdown of gas compressors and other pieces of equipment, Shut Down Valves (SDV's) close and automatic blow down valves (BDV's) open releasing pressure from the system. This is performed to augment safety as well as to comply with codes and regulations.
 - (3) During maintenance of specific equipment items, the systems are purged with nitrogen or sweet fuel gas and blown down to the flare system.
 - (4) During normal operations, sweet fuel gas is continuously used to purge the flare headers to prevent in-leakage of air.
- *Unplanned Flaring Scenarios:* Unplanned flaring events on the platform most commonly originate from platform safety trips and compressor safety trips that cause equipment shutdowns.

2.2. **Support Systems**

2.2.1 Pipelines: Pipelines present on the platform are as follows:

- 12 inch export produced gas pipeline to Platform Harmony.
- 20 inch export emulsion pipeline to Platform Harmony.

2.2.2 Power Generation: Electrical power is provided to supply the platform electrical demand from the ExxonMobil Las Flores Canyon Cogeneration facility or Southern California Edison (SCE) through a submarine cable from shore. The platform has a 900 KW, 480 Volt, 3 phase, 60 Hz, 1200 RPM diesel engine driven generator set to provide standby power for lighting, UPS system, control room pressurization fans, survival capsules, quarters building, instrument/utility air compressor and firewater pump in case of a failure of power from shore.

The platform has a 120 Volt AC Uninterruptible Power Supply System (UPS). The system consists of two 125 Volt DC, 600 Amp battery chargers, one 125 Volt DC battery bank, one 50 KVA static inverter, one automatic static transfer switch, one manual bypass switch and various distribution panel boards.

The system supplies regulated and transient-free 120 volt AC power to the essential loads such as the Distributed Control System (DCS), fire and gas alarm system, nav-aids, platform emergency lights, communication equipment and crane obstruction lights. The system is sized to provide continuous power for eight (8) hours to the Nav-Aids system and for one (1) hour to all other loads after failure of normal power has occurred.

All loads are electrically driven with the exception of the following diesel driven equipment: one pedestal crane, one firewater pump, two air compressors used primarily for abrasive blasting, the emergency generator, and the auxiliary drilling generator and associated well service equipment. In addition, several air driven pumps are also operated on the platform.

2.2.3 Crew/Utility and Supply/Work Boats: Crew/Utility boats (hereinafter referred as “crew boats”) and Supply/Work boats (hereinafter referred to as “supply boats”) are used for a variety of purposes in support of the platform.

Crew boats typically average about 2-3 round trips per day between the platform and Ellwood or other piers or ports and are used for the following activities:

1. Load, transport (receipt, movement and delivery) and unload personnel, supplies, and equipment to and from the platforms and dock or pier locations for routine operations and special logistic situations, [Examples: transport of drilling/workover fluid, casing, specialty chemicals, cement or other supplies].
2. Support supply/work boat while it is working at the platforms, [Examples: hold supply boat in position and transfer equipment or supplies].
3. Operate boat engines to maintain boat positioning while working at the platforms, docks, or piers or in open waters.
4. Support operations in conjunction with maintenance and/or repairs on platform components, [Examples: mooring buoy, boat dock, structural supports, diving operations and cathodic protection equipment].
5. Support operations in conjunction with surveys of platform and subsea components including pipelines and power cables, [Examples: side scan sonar, ROV inspection, diving inspections and marine biological inspections].
6. Support operations in conjunction with drilling and workover operations, [Examples: perforation watch and marine safety zone surveillance]
7. Support/participate in oil spill drills and actual incidents. [Examples: deploying boom and recovery equipment, taking samples and personnel exposure measurements and other spill response activities].
8. Support/participate in safety, health, and emergency drills and actual incidents. [Examples: third party requests for assistance, medevac and platform evacuation as well as other safety and health activities,-fire and explosion, well control blowout, storm, vessel collision, bomb threat and terrorist and man overboard].
9. Provide standby boat services when required due to limitations of platform survival craft capabilities and/or platform personnel count.
10. Supply marine support services to accommodate activities by local, state and federal agencies and special industry / public interest groups when requested.
11. Conduct engine source compliance tests as required by the permits or other rules and regulations.
12. Perform vessel and boat maintenance as required.

13. Travel to safe harbor from platforms, dock or pier during extreme weather or other emergency situations.

Supply boats are also routinely used in support of platform activities. Supply boats make an average of 1 round trip per day between the platform and Port Hueneme or other ports during normal operations (i.e., no drilling or well repair). Supply boats may be use more frequently during periods of drilling or well repair: Supply boats may not use the Ellwood pier for transfer of personnel in place of a crew boat. Supply boats are used for the following activities:

1. Load, transport (receipt, movement and delivery) and unload personnel, equipment and supplies to and from the platforms and Port Hueneme or other ports during routine operations and to accommodate special logistic situations, [Examples: transport of drilling/workover fluid, casing, specialty chemicals, cement or other supplies to a dock or pier to accommodate special needs of a vendor].
2. Support supply/work boat while it is working at the platforms, [Examples: hold supply boat in position and transfer equipment or supplies].
3. Operate boat engines to maintain boat positioning while working at the platforms, docks, or piers or in open waters.
4. Support operations in conjunction with maintenance and/or repairs on platform components, [Examples: mooring buoy, boat dock, structural supports, diving operations and cathodic protection equipment].
5. Support operations in conjunction with surveys of platform and subsea components including pipelines and power cables, [Examples: side scan sonar, ROV inspection, diving inspections and marine biological inspections].
6. Support operations in conjunction with drilling and workover operations, [Examples: perforation watch and marine safety zone surveillance].
7. Support/participate oil spill incident drills and actual incidents, [Examples: deploying boom and recovery equipment, taking samples and personnel exposure measurements as well as other spill response activities].
8. Support/participate in safety, health, and emergency drills and actual incidents, [Examples: third party requests for assistance, medevac and platform evacuation, safety and health activities, third party requests, fire and explosion, well control blowout, storm, vessel collision, bomb threat and terrorist and man overboard].
9. Provide standby boat services when required due to limitations of platform survival craft capabilities and/or platform personnel count.
10. Supply marine support services to accommodate activities by local, state and federal agencies and special industry/public interest groups when requested.
11. Conduct engine source compliance tests as required by the permits or other rules and regulations.
12. Perform vessel and boat maintenance as required.
13. Travel to safe harbor from platforms, dock or pier during extreme weather or other emergency situations.

- 2.2.4 Helicopters: Helicopter use currently averages about 2-3 round trips per day between the platform and the Santa Barbara Airport.

2.3. ***Drilling Activities***

- 2.3.1 Drilling: The drill rig on the platform is being used to complete the initial development drilling program that began in 1993. The rig is also used to perform well workover procedures. The rig, and related equipment, such as the drilling mud system, was specially designed for use on the platform. The mud equipment includes pumps, degasser, mud pits and related components. The mud fluid has an ROC content of less than 10 percent by weight. The major components on the drill rig, including the derrick and the superstructure, are maintained on the platform and are idle during non-drilling periods. The drilling rig and much of the associated equipment required for drilling are powered by electrical motors supplied from the platform systems. Emergency power is supplied from the 2,307 bhp diesel engine driven Auxiliary Drilling Generator.

- 2.3.2 Well Workover: ExxonMobil periodically performs well workovers.

- 2.3.3 Enhanced Recovery: Enhanced oil recovery techniques are not currently employed on the platform.

2.4. ***Maintenance/Degreasing Activities***

- 2.4.1 Paints and Coatings: Maintenance painting on the platform is conducted on a continuing basis. Normally only touch-up and equipment labeling/tagging is done with cans of spray paint. Solvents are also used as coating thinners.
- 2.4.2 Solvent Usage: Solvents not used for surface coating thinning may be used on the platform for daily operations. Usage includes cold solvent degreasing and wipe cleaning with rags.

2.5. ***Planned Process Turnarounds***

Process turnarounds on platform equipment are normally scheduled to occur as part of an integrated SYU operation that takes into account both offshore and onshore requirements. Major pieces of equipment such as gas compressors undergo maintenance as specified by the manufacturer. Maintenance of critical components is carried out during planned turnarounds according to the requirements of Rule 331 (*Fugitive Emissions Inspection and Maintenance*). The emissions associated with planned process turnarounds are incorporated in the emissions category for planned flaring.

During process turnarounds, a gas scrubber system may be used to control emissions from the flare gas header when there is no active production on the platform and the flare is out of service for maintenance and repair. The gas scrubber system is designed to control any residual vapors after equipment has been depressurized and the flare has been shut down. Two carbon canisters in series are used to remove hydrocarbons and one SulfaTreat canister is used to remove hydrogen sulfide.

2.6. ***Other Processes***

ExxonMobil has stated that no other processes exist that would be subject to permit.

2.7. Detailed Process Equipment Listing

Refer to Attachment 10.4 for a complete listing of all permitted and exempt emission units.

3.0 Regulatory Review

This Section identifies the federal, state and local rules and regulations applicable to Platform Heritage.

3.1. Rule Exemptions Claimed

⇒ District Rule 202 (*Exemptions to Rule 201*): ExxonMobil qualifies for a number of exemptions under this rule. An exemption from permit, however, does not necessarily grant relief from any applicable prohibitory rule. The following exemptions were approved by the District:

Rule Section	Equipment Description	ExxonMobil ID	District Device No
L.1	11 Cellar Deck Heat Exchangers		107690
L.1	12 Cellar Mezzanine Heat Exchangers		107691
L.1	8 Production Deck Heat Exchangers		107692
L.1	2 STV Compressor Suction Coolers	HBG-219, -220	107693
L.1	2 Production Mezzanine BX Heat Exchangers	HBG-231, -234	107694
L.3	Refrigerant compressors	CZZ-328, 329	102543
U.2.a	Remote reservoir cold solvent cleaner		5738
V.1	Anti-foam storage tank	ABJ-415	102541
V.2	Diesel fuel #2 storage tank	ABJ-401	102537
V.3	Compressor lube oil storage tank	ABJ-421	103964
V.3	Compressor lube oil storage tank	ABJ-424	102542
V.3	Compressor lube oil storage tank	ABJ-427	103963

- The cement pumping skids and the cuttings reinjection pump (Device IDS 112507, 112508, & 112509) used on the three platforms lost their prior Rule 202 F.6 drilling exemption on November 21, 2008, and have been included in this permit as permitted units at the stationary source.
- Section D.6 (*De Minimis*). As of April 2009, ExxonMobil has documented the following de minimis changes for the stationary source:

	ROC (lb/day)
POPCO	0.000
LFC	0.000
Platform Harmony	0.044
Platform Heritage	4.447
Platform Hondo	0.063
Entire Source:	4.554

- Temporary engines are used to support drilling and well workover activities. These engines are typically operated under the provisions of Rule 202.F.2 or 202.F.4. Applicability of permit requirements and associated controls for temporary engines are determined according to the rules in effect at the time of use.

⇒ District Rule 331 (*Fugitive Emissions Inspection and Maintenance*): The following exemptions were applied for and approved by the District:

- Section B.2(c) for one-half inch and less stainless steel tubing fittings.
- Section B.3(c) for PRDs vented to a closed system.
- Section B.3(c) for components totally enclosed or contained.
- Section B.2.b for components buried below the ground.
- Section B.3.b for components handling liquids or gases with ROC concentrations less than 10 percent by weight.
- Sections F.1, F.2 and F.7 for components that are unsafe-to-monitor, as documented and established in a safety manual or policy, and with prior written approval of the Control Officer.

⇒ District Rule 325 (*Crude Oil Production and Separation*): The following equipment are exempt from the requirements of Sections D.1 and D.2 pursuant to Section B.3:

- Drill Deck Drains Settling Tank (ABJ-417, District Device No 5368)
- Wellbay Drain Sump (ABH-405, District Device No 5365)
- Open Drain Sump (ABH-406, District Device No 5364)
- Skim Pile (ABH-416, District Device No 5367)

The following equipment are exempt from the requirements of Sections D, E, F.4 and H pursuant to Section B.5:

- Closed Drain Sump (MBH-132, District Device No 5363)
- Emulsion Surge Tank (MBH-110, District Device No 107171)
- Amine Sump (MBH-170, District Device No 5366)

⇒ District Rule 359 (*Flares and Thermal Oxidizers*): Under Section D.1.b, ExxonMobil has obtained District approval to comply with the exemption from Section D.1.a requirements and has offset all excess SO_x emissions at a ratio of 1:1. Unplanned flaring is exempt from the sulfur standards of this rule.

3.2. Compliance with Applicable Federal Rules and Regulations

3.2.1 40 CFR Parts 51/52{New Source Review (Nonattainment Area Review and Prevention of Significant Deterioration)}: Platform Heritage was constructed and permitted prior to the applicability of these regulations. However, all permit modifications as of September 4, 1992 are subject to District NSR requirements. Compliance with District Regulation VIII (*New Source Review*), ensures that future modifications to the facility will comply with these regulations.

- 3.2.2 40 CFR Part 55 {OCS Air Regulation} ExxonMobil is operating Platform Heritage in compliance with the requirements of this regulation.
- 3.2.3 40 CFR Part 60 {New Source Performance Standards}: The following engines on the platform are subject to 40 CFR 60 Subpart IIII: B-Side Cement Pump (ID 112508), C-Side Cement Pump (ID 112507), and Cuttings Reinjection Pump (ID 112509). The B-Side and C-Side Cement Pumps are 2006 model year Tier 3 IC engines. The Cuttings Reinjection Pump is a 2007 model year Tier 3 IC engine. The use of tier-certified IC engines demonstrates compliance with the emission limits of the NSPS. The engines must be operated and maintained according to the manufacturer's emission-related written instructions. Only emission-related settings permitted by the manufacturer may be changed.
- 3.2.4 40 CFR Part 61 {NESHAP}: None of the equipment in this permit are subject NESHAP requirements.
- 3.2.5 40 CFR Part 63 {MACT}: On June 17, 1999, EPA promulgated Subpart HH, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage. ExxonMobil has submitted HAP calculations that show each of these facilities qualifies an area source (not a major source), and thus are not subject to the MACT. This is based on the definitions of "facility" and "major source" in the MACT. The data shows that each platform has less than 10 TPY combined HAPs.
- 3.2.6 40 CFR Part 63 Maximum Achievable Control Technology (MACT) Standards Subpart ZZZZ - The revised National Emission Standard for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE) was published in the Federal Register on January 18, 2008. An affected source under the NESHAP is any existing, new, or reconstructed stationary RICE located at a major source or area source.

Existing non-emergency non-black start compression ignition RICE must comply with the applicable emission and operating limits by no later than May 3, 2013. The following engine on the platform is subject to this requirement: East Crane (ID5350). The following operating requirements apply:

- (1) Limit concentration of CO in the exhaust to 23 ppmvd @ 15 percent O₂; or
- (2) Reduce CO emissions by 70 percent or more.

The operator must conduct an initial performance test within 180 days after the compliance date.

Notifications are not required for existing stationary emergency RICE.

Existing emergency standby compression ignition RICE must comply with the applicable operating limits by no later than May 3, 2013. The following engines on the platform are subject to this requirement: Emergency Production Generator (ID 5371), Emergency Drilling Generator (ID 5370), Emergency Firewater Pump PBE-357 (ID 5372), and Emergency Firewater Pump PBE-367 (ID 7143). The following operating requirements apply:

- (1) change the oil and filter every 500 hours of operation or annually, whichever comes first;

- (2) inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first;
- (3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

New stationary RICE that are subject to 40 CFR 60 Subpart IIII are not subject to any further requirements under 40 CFR 63 Subpart ZZZZ. The following engines on the platform are subject to 40 CFR 60 Subpart IIII, so they are not subject to any further requirements under this NESHAP: B-Side Cement Pumping Skid (ID 112508), C-side Cement Pumping Skid (ID 112507), and Cuttings Reinjection Pump (ID 112509).

- 3.2.7 40 CFR Part 64 {Compliance Assurance Monitoring}: This rule became effective on April 22, 1998. At the time of this Part 70 permit renewal the requirements of Part 64 were not applicable to Platform Heritage. The platform does not have any equipment, which uncontrolled would exceed 100 TPY of any criteria pollutant.
- 3.2.8 40 CFR Part 70 {Operating Permits}: This Subpart is applicable to Platform Heritage. Table 3.1 lists the federally-enforceable District promulgated rules that are “generic” and apply to Platform Heritage. Table 3.2 lists the federally-enforceable District promulgated rules that are “unit-specific”. These tables are based on data available from the District’s administrative files and from ExxonMobil’s Part 70 Operating Permit application.

In its Part 70 permit application (Forms I and J), ExxonMobil certified compliance with all existing District rules and permit conditions. This certification is also required of ExxonMobil semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that ExxonMobil complies with the provisions of all applicable Subparts.

3.3. *Compliance with Applicable State Rules and Regulations*

- 3.3.1 Division 26. Air Resources {California Health & Safety Code}: The administrative provisions of the Health & Safety Code apply to this facility and will be enforced by the District. These provisions are District-enforceable only.
- 3.3.2 California Administrative Code Title 17 {Sections 92000 – 92450}: These sections specify the standards by which abrasive blasting activities are governed throughout the State. All abrasive blasting activities at Platform Heritage are required to conform to these standards. Compliance will be assessed through onsite inspections. These standards are District-enforceable only. However, CAC Title 17 does not preempt enforcement of any SIP-approved rule that may be applicable to abrasive blasting activities.
- 3.3.3 Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines (CCR Section 93115, Title 17): This ATCM applies for all stationary diesel-fueled engines rated over 50 brake horsepower (bhp) at this facility. On March 17, 2005, District Rule 202 was revised to remove the compression-ignited engine (e.g. diesel) permit exemption for units rated over 50 bhp to allow the District to implement the State’s ATCM for Stationary Compression Ignition Engines. Compliance shall be assessed through onsite inspections and reporting. The operating requirements and emission standards outlined in the ATCM do not apply to stationary diesel-fueled engines solely used on the OCS. However these OCS engines are required to meet

fuel, recordkeeping, reporting, and monitoring requirements outlined in the ATCM. On January 30, 2006 the DICE ATCM was incorporated into 40 CFR Part 55, making the requirements of the DICE ATCM federally enforceable in the OCS.

- 3.3.4 California Administrative Code Title 17 {Sections 93118.5}: This section requires diesel-powered harborcraft to meet certain emission standards and operational requirements. New vessels brought into California must comply with this regulation immediately, while existing vessels must meet the compliance dates specified in the regulation.

3.4. Compliance with Applicable Local Rules and Regulations

- 3.4.1 Applicability Tables: In addition to Tables 3.1 and 3.2, Table 3.3 lists the non-federally enforceable District promulgated rules that apply to Platform Heritage.
- 3.4.2 Rules Requiring Further Discussion: This section provides a more detailed discussion regarding the applicability and compliance of certain rules.

The following is a rule-by-rule evaluation of compliance for Platform Heritage:

Rule 301 - Circumvention: This rule prohibits the concealment of any activity that would otherwise constitute a violation of Division 26 (Air Resources) of the California H&SC and District rules and regulations. To the best of the District's knowledge, ExxonMobil is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for which a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringelmann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringelmann Chart. Sources subject to this rule include: the flare, the Central Process Heater and all diesel-fired piston internal combustion engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured through Visible Emissions Monitoring per condition 9.B.2 by ExxonMobil staff and requiring all engines to be maintained according to manufacturer maintenance schedules per the District-approved IC Engine Particulate Matter Operation and Maintenance Plan.

Rule 303 - Nuisance: This rule prohibits the OCS operator from causing a public nuisance due to the discharge of air contaminants. This rule does not apply to the platform since it is not included in the OCS Air Regulation.

Rule 305 - Particulate Matter, Southern Zone: Platform Heritage is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of specified concentrations measured in gr/scf. The maximum allowable concentrations are determined as a function of volumetric discharge, measured in scfm, and are listed in Table 305(a) of the rule. Sources subject to this rule include: the flare, the Central Process Heater and all diesel-fired IC engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules. Rule 359 addresses the need for the flare to operate in a smokeless fashion.

Rule 309 - Specific Contaminants: Under Section "A", no source may discharge sulfur compounds and combustion contaminants in excess of 0.2 percent as SO₂ (by volume) and 0.3 gr/scf (at 12% CO₂) respectively. Sulfur emissions due to flaring of sweet gas will comply with the SO₂ limit. All diesel powered piston IC engines have the potential to exceed the combustion contaminant limit if not properly maintained (see discussion on Rule 305 above for compliance).

Rule 310 - Odorous Organic Compounds: This rule prohibits the discharge of H₂S and organic sulfides that result in a ground level impact beyond the property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. No measured data exists to confirm compliance with this rule, however, all produced gas from Platform Heritage is collected for sales, re-injection or is collected by vapor recovery (i.e., no venting occurs). As a result, it is expected that compliance with this rule will be achieved. Further, the District has not recorded any odor complaints from this facility.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted on Platform Heritage to 0.5 percent (by weight) for liquids fuels and 15 gr/100 scf (calculated as H₂S) {or 239 ppmvd} for gaseous fuels. All piston IC engines on the Platform Heritage and on the crew and supply boats are expected to be in compliance with the liquid fuel limit since they are required to use CARB diesel fuel with 0.0015% sulfur content. The Central Process Heater is expected to be in compliance with the gaseous fuel limit as determined by an in-line hydrogen sulfide analyzer for the natural gas and fuel analysis documentation for the propane. The flare relief system is not subject to this rule (see discussion under Rule 359).

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the discharge of emissions of both photochemically and non-photochemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used on the platform during normal operations for degreasing by wipe cleaning and for use in paints and coatings in maintenance operations. There is the potential to exceed the limits under Section B.2 during significant surface coating activities. ExxonMobil will be required to maintain records to ensure compliance with this rule.

Rule 318 - Vacuum Producing Devices or Systems – Southern Zone: This rule prohibits the discharge of more than 3 pounds per hour of organic materials from any vacuum producing device or system, unless the organic material emissions have been reduced by at least 90 percent. ExxonMobil has stated that there are no equipment subject to this rule.

Rule 321 – Solvent Cleaning Operations: This rule sets equipment and operational standards for degreasers using organic solvents. There is one remote reservoir degreasing unit (cold solvent cleaning) on the platform. This unit is exempt from all provisions of this rule with the exception of Section G.2 (requirement to keep the unit covered at all times when not in use). Degreaser compliance and solvent use will be determined through District inspection and the operating and recordkeeping requirements of the rule.

Rule 322 - Metal Surface Coating Thinner and Reducer: This rule prohibits the use of photochemically reactive solvents for use as thinners or reducers in metal surface coatings. ExxonMobil will be required to maintain records during maintenance operations to ensure compliance with this rule.

Rule 323 - Architectural Coatings: This rule sets standards for the application of surface coatings. The primary coating standard that will apply to the platform is for Industrial Maintenance Coatings which has a limit of 340 gram ROC per liter of coating, as applied. ExxonMobil will be required to comply with the Administrative requirements under Section F for each container on the platform.

Rule 324 - Disposal and Evaporation of Solvents: This rule prohibits any source from disposing more than one and a half gallons of any photochemically reactive solvent per day by means that will allow the evaporation of the solvent to the atmosphere. ExxonMobil will be required to maintain records to ensure compliance with this rule. Solvents used during operations (e.g., for degreasing and wipe cleaning) will be limited to the non-photochemically reactive type.

Rule 325 - Crude Oil Production and Separation: This rule, adopted January 25, 1994, applies to equipment used in the production, processing, separation, gathering, and storage of oil and gas prior to custody transfer. The primary requirements of this rule are under Sections D and E. Section D requires the use of vapor recovery systems on all tanks and vessels, including waste water tanks, oil/water separators and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. Production and test separators are all connected to gas gathering systems and relief valves are connected to the flare relief system. Compliance with Section E is met by directing all produced gas to sales, injection, gas lift or to the flare relief system.

Rule 326 - Storage of Reactive Organic Liquids: This rule applies to equipment used to store reactive organic compound liquids with a vapor pressure greater than 0.5 psia. There is no platform equipment subject to this rule.

Rule 327 - Organic Liquid Cargo Tank Vessel Loading: There are no organic liquid cargo tank loading operations associated with Platform Heritage.

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). Per Section B.2, the ExxonMobil SYU stationary source emits to the atmosphere more than 5 lb/hr of non-methane hydrocarbons, oxides of nitrogen and sulfur oxides and more than 10 lb/hr of particulate matter, thereby triggering the Section C.2 requirement that the need and application of CEMs be evaluated. An in-line hydrogen sulfide analyzer is required on the fuel gas line to the Central Process Heater to ensure compliance with permitted emission limits and Rule 311.

Rule 330 - Surface Coating of Metal Parts and Products: This rule sets standards for many types of coatings applied to metal parts and products. In addition to the ROC standards, this rule sets operating standards for application of the coatings, labeling and recordkeeping. It is not anticipated that ExxonMobil will trigger the requirements of this rule. Compliance shall be based on site inspections.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas production fields. ExxonMobil has submitted and received final approval for a Fugitive Inspection and Maintenance Plan. Ongoing compliance with the many provisions of this rule will be assessed via platform inspection by District personnel using an organic vapor analyzer and through analysis of operator records. Platform Heritage does not perform any routine venting of hydrocarbons to the atmosphere.

Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines: This rule applies to all engines with a rated brake horsepower of 50 or greater. The emergency standby IC engines at the facility include two firewater pump engines and one generator that are no longer exempt from permit. However, they are compression ignition emergency standby engines and are exempt from the provisions of the Rule per Section B.1.d. The diesel-fired pedestal crane engine, the diesel fired cement pumps and the cuttings reinjection pump are subject to the NO_x, ROC, and CO standards under Section E.4. The revised Rule became effective on the OCS on November 21, 2008. Ongoing compliance will be achieved through implementation of the District-approved Maintenance Plan required under Section F and through source testing as applicable.

Rule 342 - Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters: This rule sets emission standards for external combustion units with a rated heat input greater than 5.0 MMBtu/hr. Platform Heritage has a Central Process Heater rated at 27.200 MMBtu/hr. The NO_x and CO emission standards of this rule are 30 ppmv and 400 ppmv (or 0.036 lb/MMBtu and 0.297 lb/MMBtu) respectively. Compliance is met by the use of low-NO_x burners. Ongoing compliance is achieved through biennial source testing.

Rule 343 - Petroleum Storage Tank Degassing: This rule applies to the degassing of any above-ground tank, reservoir or other container of more than 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 2.6 psia or between 20,000 gallons and 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 3.9 psia. The only vessel to which this rule applies is the emulsion surge tank. Ongoing compliance with this rule will be achieved through the section F and G reporting and recordkeeping requirements of the rule.

Rule 346 - Loading of Organic Liquids: This rule applies to the transfer of organic liquids into an organic liquid cargo vessel. For this rule only, an organic liquid cargo vessel is defined as a truck, trailer or railroad car and, as such, this rule does not affect OCS sources.

Rule 353 – Adhesives and Sealants: This rule applies to the use of adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers. Compliance shall be based on site inspections.

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. Compliance with this rule has been documented. A detailed review of compliance issues is as follows:

§ D.1 - Sulfur Content in Gaseous Fuels: Part (a) limits the total sulfur content of all planned flaring from South County flares to 15 gr/100 cubic feet (239 ppmv) calculated as H₂S at standard conditions. A methyl diethanolamine sulfur treating unit which reduces the sulfur content of a portion of the platform produced gas will provide the flare with purge and pilot gas (445 scfh - planned flaring) that is within the limits of this rule (sulfur is limited to 30 ppmv by prior agreements). For all other planned emissions associated with platform flaring volumes, ExxonMobil has obtained District approval to comply with the part (b) exemption of this rule that requires excess SO_x emissions to be offset at a ratio of 1:1. Unplanned flaring is exempt from the sulfur standards of this rule.

§ D.2 - Technology Based Standard: Requires all flares to be smokeless and sets pilot flame requirements. The flare on Platform Heritage is in compliance with this section.

§ D.3 - Flare Minimization Plan: This section requires sources to implement flare minimization procedures so as to reduce SO_x emissions. The Planned Flaring volume is 66 million standard cubic feet per month. ExxonMobil has fully implemented their Flare Minimization Plan.

Rule 360 – Emissions of Nitrogen from Large Water Heaters and Small Boilers: The permittee shall comply with the requirements of this rule whenever a new boiler, process heater or other external combustion device is added or an existing unit is replaced. An ATC/PTO permit shall be obtained prior to installation of any grouping of Rule 360 applicable boilers or hot water heaters whose combined system design heat input rating exceeds 2.000 MMBtu/hr. An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane.

Rule 361 – Small Boilers, Steam Generators and Process Heaters: The permittee shall comply with the requirements of this rule whenever a new boiler, process heater or other external combustion device is added or an existing unit is replaced. An ATC permit shall be obtained prior to installation, replacement, or modification of any existing Rule 361 applicable boiler or water heater rated over 2.000 MMBtu/hr. An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane.

Rule 505 - Breakdown Conditions: This rule describes the procedures that ExxonMobil must follow when a breakdown condition occurs to any emissions unit associated with Platform Heritage. A breakdown condition is defined as an unforeseeable failure or malfunction of (1) any air pollution control equipment or related operating equipment which causes a violation of an emission limitation or restriction prescribed in the District Rules and Regulations, or by State law, or (2) any in-stack continuous monitoring equipment, provided such failure or malfunction:

- a. Is not the result of neglect or disregard of any air pollution control law or rule or regulation;
- b. Is not the result of an intentional or negligent act or omission on the part of the owner or operator;
- c. Is not the result of improper maintenance;
- d. Does not constitute a nuisance as defined in Section 41700 of the Health and Safety Code;
- e. Is not a recurrent breakdown of the same equipment.

Rule 603 - Emergency Episode Plans: Section "A" of this rule requires the submittal of *Stationary Source Curtailment Plan* for all stationary sources that can be expected to emit more than 100 tons per year of hydrocarbons, nitrogen oxides, carbon monoxide or particulate matter. ExxonMobil submitted such a plan on July 23, 1994. This Plan was updated on January 24, 1997.

Rule 810 – Federal Prevention of Significant Deterioration: This rule was adopted January 20, 2011 to incorporate the federal Prevention of Significant Deterioration rule requirements into

the District's rules and regulations. Future projects at the facility will be evaluated to determine whether they constitute a new major stationary source or a major modification.

3.5. *Compliance History*

This section contains a summary of the compliance history for this facility and was obtained from documentation contained in the District's Administrative file.

3.5.1 Variances: ExxonMobil has sought variance relief per Regulation V and received one Regular (R) and one Interim (I) Variance since May 2006.

68-09-I Granted 5/28/2009. District Rule 342.D.1 and 206. Operate central process heater in excess of permitted CO emission limits.

69-09-R Granted 8/5/2009. District Rule 342.D.1 and 206. Operate central process heater in excess of permitted CO emission limits.

3.5.2 Violations: The last platform inspections occurred during February 2012. The inspector did not document any violations. The following violations have been documented since the last permit reevaluation:

VIOLATION TYPE	NUMBER	ISSUE DATE	DESCRIPTION OF VIOLATION
NOV	9758	2/16/2011	Exceeding the number of allowable major gas leaks from “other” components.

3.5.3 Significant Historical Hearing Board Actions/NOVs: There have been no significant *historical* Hearing Board actions since the initial Part 70 permit was issued.

Table 3.1 Generic Federally Enforceable District Rules

Generic Requirements	Affected Emission Units	Basis for Applicability	Adoption Date
<u>RULE 101</u> : Compliance by Existing Installations	All emission units	Emission of pollutants	June 1981
<u>RULE 102</u> : Definitions	All emission units	Emission of pollutants	March 17, 2011
<u>RULE 103</u> : Severability	All emission units	Emission of pollutants	October 23, 1978
<u>RULE 201</u> : Permits Required	All emission units	Emission of pollutants	April 17, 1997
<u>RULE 202</u> : Exemptions to Rule 201	Applicable emission units, as listed in form 1302-H of the Part 70 application	Insignificant activities/emissions, per size/rating/function	March 17, 2011
<u>RULE 203</u> : Transfer	All emission units	Change of ownership	April 17, 1997
<u>RULE 204</u> : Applications	All emission units	Addition of new equipment of modification to existing equipment.	April 17, 1997
<u>RULE 205</u> : Standards for Granting Permits	All emission units	Emission of pollutants	April 17, 1997
<u>RULE 206</u> : Conditional Approval of Authority to Construct or Permit to Operate	All emission units	Applicability of relevant Rules	October 15, 1991
<u>RULE 207</u> : Denial of Applications	All emission units	Applicability of relevant Rules	October 23, 1978
<u>RULE 208</u> : Action on Applications – Time Limits	All emission units. Not applicable to Part 70 permit applications.	Addition of new equipment of modification to existing equipment.	April 17, 1997
<u>RULE 212</u> : Emission Statements	All emission units	Administrative	October 20, 1992
<u>RULE 301</u> : Circumvention	All emission units	Any pollutant emission	October 23, 1978
<u>RULE 302</u> : Visible Emissions	All emission units	Particulate matter emissions	June 1981
<u>RULE 305</u> : PM Concentration – South Zone	Each PM source	Emission of PM in effluent gas	October 23, 1978
<u>RULE 309</u> : Specific	All emission units	Combustion contaminants	October 23, 1978

Generic Requirements	Affected Emission Units	Basis for Applicability	Adoption Date
Contaminants			
<u>RULE 310</u> : Odorous Org. Sulfides	All emission units	Emission of organic sulfides	October 23, 1978
<u>RULE 311</u> : Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur	October 23, 1978
<u>RULE 317</u> : Organic Solvents	Emission units using solvents	Solvent used in process operations.	October 23, 1978
<u>RULE 318</u> : Vacuum Producing Devices – Southern Zone	All systems working under vacuum	Operating pressure	October 23, 1978
<u>RULE 321</u> : Solvent Cleaning Operations	Cold solvent cleaning unit EQ No. 14-2	Solvent used in process operations.	September 20, 2010
<u>RULE 322</u> : Metal Surface Coating Thinner and Reducer	Emission units using solvents	Solvent used in process operations.	October 23, 1978
<u>RULE 323</u> : Architectural Coatings	Paints used in maintenance and surface coating activities	Application of architectural coatings.	November 15, 2001
<u>RULE 324</u> : Disposal and Evaporation of Solvents	Emission units using solvents	Solvent used in process operations.	October 23, 1978
<u>RULE 353</u> : Adhesives and Sealants	Emission units using adhesives and sealants	Adhesives and sealants use.	August 19, 1999
<u>RULE 505.A, B1, D</u> : Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.	October 23, 1978
<u>RULE 603</u> : Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	ExxonMobil – SYU Project is a major source.	June 15, 1981
<u>REGULATION VIII</u> : New Source Review	All emission units	Addition of new equipment of modification to existing equipment. Applications to generate ERC Certificates.	April 17, 1997
<u>RULE 810</u> : Federal Prevention of Significant Deterioration	New or modified emission units	Major modifications	January 20, 2011
<u>RULE 901</u> : New Source Performance Standards (NSPS)	All emission units	ExxonMobil SYU Project is a major source.	September 20, 2010
<u>RULE 1001</u> : National Emission Standards for Hazardous Air Pollutants (NESHAPS)	All emission units	ExxonMobil SYU Project is a major source.	October 23, 1993
<u>REGULATION XIII (RULE 1301)</u> : Part 70 Operating Permits	All emission units	ExxonMobil – SYU Project is a major source.	September 18, 1997

Generic Requirements	Affected Emission Units	Basis for Applicability	Adoption Date
<u>REGULATION XIII (RULES 1302-1305):</u> Part 70 Operating Permits	All emission units	ExxonMobil – SYU Project is a major source.	November 9, 1993

Table 3.2 Unit-Specific Federally Enforceable District Rules

Unit-Specific Requirements	Affected Emission Units (District Device No)	Basis for Applicability	Adoption Date
<u>RULE 325:</u> Crude Oil Production and Separation	5363, 5364, 6366, 102539, 102540	All pre-custody production and processing emission units	July 19, 2001
<u>RULE 331:</u> Fugitive Emissions Inspection & Maintenance	102526 – 102536, and 102516 - 102525	Components emit fugitive hydrocarbons.	December 10, 1991
<u>RULE 333:</u> Control of Emissions from Reciprocating IC Engines	5350, 5370, 5371, 5372, 7143	IC engines exceeding 50 bhp rating.	June 19, 2008
<u>RULE 359:</u> Flares and Thermal Oxidizers	102383 - 102385	Flaring	June 28, 1994
Rule 360: Emissions of Oxides of Nitrogen From Large Water Heaters and Small Boilers	No units are currently subject to this rule.	External combustion units with a rated heat input greater than or equal to 75,000 Btu/ hour up to and including 2,000,000 Btu/hour.	October 17, 2002
Rule 361: Small Boilers, Steam Generators, and Process Heaters	No units are currently subject to this rule.	Any boiler, steam generator, and process heater with a rated heat input capacity greater than 2 MMBtu/hour and less than 5 MMBtu/hour.	January 17, 2008

Table 3.3 Non-Federally-Enforceable District Rules

Requirement	Affected Emission Units	Basis for Applicability	Adoption Date
<u>RULE 210</u> : Fees	All emission units	Administrative	March 17, 2005
<u>RULE 310</u> : Organic Sulfides	All emission units	Odorous sulfide emissions	October 23, 1978
<u>RULE 352</u> : Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters	New water heaters and furnaces	Upon installation	October 20, 2011
<u>RULES 501-504</u> : Variance Rules	All emission units	Administrative	October 23, 1978
<u>RULE 505.B2, B3, C, E, F, G</u> : Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.	October 23, 1978
<u>RULES 506-519</u> : Variance Rules	All emission units	Administrative	October 23, 1978

4.0 Engineering Analysis

4.1. General

The engineering analyses performed for this permit were limited to the review of:

- Emission factors and calculation methods for each emissions unit
- Emission control equipment (including RACT, BACT, NSPS, NESHAP, MACT)
- Emission source testing, sampling, CEMS, CAM
- Process monitors needed to ensure compliance

Unless noted otherwise, default ROC/THC reactivity profiles from the District's document titled "*VOC/ROC Emission Factors and Reactivities for Common Source Types*" dated 7/13/98 (ver 1.1) was used to determine non-methane, non-ethane fraction of THC.

4.2. Stationary Combustion Sources

The stationary combustion sources associated with Platform Heritage consist of diesel-fired piston internal combustion engines, the flare relief system and the central process heater. Primary power on the platform is supplied by an ExxonMobil onshore cogeneration plant via a subsea power cable to the platform.

- 4.2.1 Piston Internal Combustion Engines: All platform internal combustion engines are diesel-fuel fired. The largest source of IC engine emissions is the pedestal crane. Other stationary IC engines on the platform rated over 50-bhp include two cement pump engines, one cuttings reinjection pump, one drilling rig emergency electrical generator, one production emergency generator, two emergency firewater pumps, and two escape capsules. Platform Heritage has one escape capsule which is rated at less than 50 bhp. The following calculation methodology is similar for all stationary IC engines:

$$ER = \left(\frac{EF * BHP * BSFC * LCF * HPP}{10^6} \right)$$

where:

ER =	emission rate (lb/period)
EF =	pollutant specific emission factor (lb/MMBtu)
BHP =	engine rated max brake-horsepower (bhp)
BSFC =	engine brake specific fuel consumption (Btu/bhp-hr)
LCF =	liquid fuel correction factor, LHV to HHV
HPP =	operating hours per time period (hrs/period)

The emission factor is an energy based value using the higher heating value (HHV) of the fuel. As such, an energy based BSFC value must also be based on the HHV. Manufacturer BSFC data are typically based on lower heating value (LHV) data and thus require a conversion (LCF) to the HHV basis. For diesel fuel oil, the HHV values are typically 6 percent greater than the corresponding LHV data. Volume or mass based BSFC data do not require conversion.

Crane engine: The pedestal crane is driven by a Detroit Diesel Model 8V-92TA engine rated at 450 bhp. This engine is not equipped with emission controls. The emission factors for PM₁₀, CO and ROC are based on USEPA AP-42, Table 3.3-1 (10/96) and the SO_x emission factor is based on mass balance. The NO_x emission factor is based on Rule 333 limits. Per AP-42, PM is assumed to equal PM₁₀. The engine complies with the Rule 333 limits of 8.4 g/bhp-hr or 796 ppmv at 15 percent oxygen. Ongoing compliance with Rule 333 will be accomplished by quarterly inspections per Section E of this rule and biennial source testing.

Drilling Support Engines: The cuttings reinjection pump is driven by a Tier 3 Detroit Diesel model 8V92TAV diesel-fired engine rated at 450 bhp. It is a model year 2007 engine. The two cement pumps are each driven by a Tier 3 Cummins model QSM11-C diesel-fired engine rated at 500 bhp. These two engines are model year 2006. Tier 3 emission factors were used in the emission calculations for these engines.

The IC engines on the platform are not equipped with diesel fuel flow metering devices. All IC engines are equipped with non-resettable hour meters. The actual engine usage is logged during each time the engine is fired. Emissions are calculated using total elapsed run time, the maximum rated engine bhp rating and BSFC data (from Table 5.1) to determine the number of gallons consumed per unit time.

- 4.2.2 External Combustion Equipment: The only external combustion equipment on Platform Heritage is the central process heater. The ROC and PM emission factors are based on USEPA, AP-42 Table 1.4-2 (3/98). Per AP-42, PM₁₀ is assumed to equal PM. The SO_x emission factor is based on mass balance. The NO_x and CO emission factor is based on the Rule 342 limits of 30 ppmv and 400 ppmv at 3 percent oxygen (0.036 lb/MMBtu and 0.297 lb/MMBtu). This unit is equipped with an orifice meter connected to the Distributed Control System for fuel monitoring purposes. The pollutant emission rates for this equipment will be determined by the permitted emission factors (lb/MMBtu) and fuel usage rates. Periodic analysis of the fuel gas will be conducted to determine the HHV and sulfur content of the fuel gas.

The sweet gas produced from the sandstone formation may also be used as fuel gas to the central process heater. The produced gas is ~30 ppmv H₂S, meeting the sulfur content requirement of District Rule 311.

Propane (HD-5 specification) fuel may also be fired as a backup fuel when the natural gas supply has been interrupted. The NO_x and CO emission factors are based on Rule 342 limits. ROC and PM emission factors are based on USEPA, AP-42 Table 1.4-1 (3/98) – the emission factor basis is the same as natural gas on a heat input basis. Per AP-42, PM₁₀ is assumed to equal PM. The SO_x emission factor is based on mass balance using the Gas Processors Association standard for HD-5 (123 ppmw).

- 4.2.3 Flare Relief System: The flare relief system consists of a header that connects to various PSVs on production and test vessels, compressors, glycol system and pigging vessels. The flare is a Kaldair model EAL-602 with a design heat release of 3820 MMBtu/hr.

Planned and unplanned flaring events occur on the platform. Planned events include purge and pilot requirements. NO_x, CO and ROC emission factors are based on USEPA AP-42, Section 13.5 (9/91). SO_x emissions are based on mass balance calculations. The PM emission factor is

based on District Flare Study – Phase I Report (7/91). The PM₁₀/PM ratio is assumed to equal 1.0. The ROC/TOC ratio is assumed to equal 0.86.

- *Purge and Pilot* - The H₂S concentration of the purge and pilot gas is continuously monitored by a Houston Atlas H₂S detector located on the amine sweetening unit.
- *Planned – Continuous* - The flare header is equipped with a Fluid Components LT81A Gas Mass Flow Meter that is capable of detecting a minimum flow rate of 1,503 scfh. As such, there is no practical method for assessing flow rates below 1,503 scfh. Based on EPA and CARB's data reporting guidelines, a value of half the minimum detection limit is assumed to be "continuous" planned flaring. The H₂S concentration of the "continuous" planned flare gas is assumed to be 20,000 ppmv which corresponds to the anticipated average H₂S concentration of the platform produced gas.
- *Planned and Unplanned Other* - Other planned flaring sulfur levels will be determined by gas detector tubes (or equivalent District-approved method). Unplanned flaring is exempt from the sulfur standards of Rule 359.

The emissions for both planned and unplanned flaring events are calculated. The SO_x emission factor is determined using the equation: (0.169)(ppmv S)/(HHV). The calculation methodology for the flare emissions is:

$$ER = \frac{EF * SCFPP * HHV}{10^6}$$

where: ER = emission rate (lb/period)
 EF = pollutant specific emission factor (lb/MMBtu)
 SCFPP = gas flow rate per operating period (scf/period)
 HHV = gas higher heating value (Btu/scf)

To meet the requirements of Rule 359, ExxonMobil uses purge and pilot gas that complies with the rule limit of 239 ppmv and has obtained exemption approval to exceed the sulfur limits for all other planned flaring activities. The sweet gas produced from the sandstone formation may also be used as fuel gas to the flare relief system. The produced gas is ~30 ppmv H₂S, meeting the sulfur content requirement of District Rule 311.

4.3. ***Fugitive Hydrocarbon Sources***

4.3.1 General: Fugitive hydrocarbon emissions occur from leaks in process components such as valves, connections, pumps, compressors and pressure relief devices. Each of these component types may be comprised of several potential "leak paths" at the facility. For example, leak paths associated with a valve include the valve stem, bonnet and the upstream and downstream flanges. The total number of leak paths at the facility must be determined to perform fugitive emission calculations.

4.3.2 Emission Factors: Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been quantified using empirical models (Tecolote Report, 1986). The equation from Model B is utilized. The uncontrolled emission factors are taken from District Policy & Procedure 6100.061 (9/25/98). The number of emission leak-paths (including

pump and compressor seals and excluding all exempt components) were determined by the operator and verified by District staff by a site check of a representative number of P&IDs. Emissions are based on a total of 16,939 gas/condensate component-leakpaths and 10,052 oil/emulsion component-leakpaths. The calculation methodology for the fugitive emissions is:

$$ER = \left(\frac{EF * CLP}{24} \right) * (1 - CE) * HPP$$

where: ER = emission rate (lb/period)
 EF = ROC emission factor (lb/clp-day)
 CLP = component leak-path (clp)
 CE = control efficiency
 HPP = operating hours per time period (hrs/period)

- 4.3.3 **Emission Controls:** Differing emission control efficiencies are credited to all components that are safe to monitor (as defined per Rule 331) due to the implementation of a District-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements. The control efficiencies vary based on component design, monitoring frequency, and leak detection threshold. This facility operates Category B valves and flanges/connections (85% control), Category F valves and flanges/connections (90% control) which are subject to BACT, and 80% for the remainder of the safe-to-monitor components. Unsafe to monitor components are not eligible for I&M control credit. (See Permit Guideline Document 15 – *Fugitive Emissions from Valves, Fittings, Flanges, Pressure Relief Devices, Seals, and Other Components – Component-Leakpath Method* for a detailed discussion of the various categories defined for valves and flanges/connections).

ExxonMobil has classified a large number of components as “emitters less than 500 ppmv” (Category B) and “emitters less than 100 ppmv” (Category F). Category B component-leakpaths are maintained at or below 500 ppmv as methane, monitored quarterly per EPA Reference Method 21. For such Category B component-leakpaths, screening values above 500 ppmv trigger the Rule 331 repair process per the minor leak schedule. Category C component-leakpaths are maintained at or below 100 ppmv as methane, monitored quarterly per EPA Reference Method 21. Category F component-leakpaths are subject to NSR BACT provisions of Rule 331. Category F components are maintained at or below 100 ppmv as methane, monitored quarterly per EPA Reference Method 21. Screening values above 100 ppmv trigger the Rule 331 repair process per the minor leak schedule for Category C and F component-leakpaths. Table 4.2 (*Rule 331 BACT Requirements*) lists the specific BACT requirements for these components.

Ongoing compliance is determined in the field by inspection with an organic vapor analyzer and verification of operator records.

4.4. **Crew and Supply Vessels**

ExxonMobil uses crew and supply boats in support of Platform Heritage. For these boats, two categories of boats may be used. One type is for dedicated project usage (DPV) that is controlled for NO_x and the other is used as a spot-charter and may be uncontrolled for NO_x. The spot-charter usage is limited to 10 percent of actual (DPV) boat usage

4.4.1 Supply Boat: The supply boat now used to establish the potential to emit is the *M/V Santa Cruz*.

- *Main Engines* - This boat is equipped with two main propulsion diesel-fired IC engines (CAT 3516B). These engines are rated at 2,000 bhp at 1600 rpm for continuous duty ("A" rating). These engines are optimized for low emissions (NO_x) through use of Dual Advanced Diesel Engine Management (ADEMII) modules with electronically controlled unit injectors, as well as dual turbochargers and a separate circuit aftercooler core. The NO_x emission factor is based on the existing operating permit limit of 8.4 g/bhp-hr (337 lb/1000 gallons). ROC and CO emission factors have been updated to reflect the larger size of these engines and are taken from Table II-3.3 of USEPA, AP-42 (Volume II). Sulfur oxide emissions are based on mass balance calculations assuming 0.0015 weight percent sulfur diesel fuel (CARB diesel).
- *Auxiliary Engines* - Auxiliary diesel-fired engines on this vessel include two-170 kW CAT 3306B DIT generator sets each powered by identical 245 bhp engines and one bow thruster powered by a CAT 3408C DITA 500 bhp engine. These auxiliary engines are not controlled. The same USEPA AP-42 emissions factors used in the original operating permit are still applicable. Sulfur oxide emissions are based on mass balance calculations assuming 0.0015 weight percent sulfur diesel fuel (CARB diesel).

4.4.2 Crew Boat: The crew boat now used to establish the potential to emit is the *M/V Callie Jean*.

- *Main Engines* - This boat is equipped with four main propulsion diesel-fired IC engines (DDC/MTU 12V-2000). These engines are rated at 965 bhp each for continuous duty for a total of 3,860 bhp. These engines are optimized for low emissions (NO_x) through use of DDEC electronic control systems, as well as dual turbochargers and intercooling. The NO_x emission factor is based on the existing OCS operating permit limit of 8.4 g/bhp-hr (337 lb/1000 gallons). ROC and CO emission factors have been updated to reflect the larger size of these engines and are taken from Table II-3.3 of USEPA, AP-42 (Volume II). Sulfur oxide emissions are based on mass balance calculations assuming 0.0015 weight percent sulfur diesel fuel (CARB diesel).
- *Auxiliary Engines* - Auxiliary diesel-fired engines on this boat include two 131 bhp diesel-driven generators (Detroit Diesel 3-71). These auxiliary engines are not controlled for NO_x.

The permit is assessing emission liability based on a single emission factor (the cruise mode). For engines with the controls listed above, a full load NO_x emission factor of 8.4 g/bhp-hr (337 lb/1000 gallons) is used. Sulfur oxide emissions are based on mass balance calculations assuming 0.0015 weight percent sulfur diesel fuel. Other main engine vessel emission factors are taken from USEPA, AP-42 (Volume II). For the auxiliary and bow thruster engines, emission factors are taken from USEPA, AP-42 (Volume I). Uncontrolled NO_x main engine emission factors for spot-charter supply boat usage are assumed to be 14 g/bhp-hr (561 lb/1000 gallons).

Per DOI No. 0042 Mod - 01, ExxonMobil installed new Tier II engines on the *M/V Broadbill*. The four main propulsion engines are Tier II Detroit Diesel Series 60 engines (each rated at 600 bhp). The two auxiliary engines are Tier II Northern Lights Model

M40C2 engines (each rated at 62 bhp). The main propulsion engines are optimized for low emissions (NO_x) through use of DDEC electronic control systems, as well as turbochargers.

- 4.4.3 **Calculation Methods:** The permit assesses emission liability based solely on a single emission factor (the cruise mode). The calculation methodology for the crew and supply boat main engine emissions is:

$$ER = \left(\frac{EF * EHP * BSFC * EL * TM}{10^3} \right)$$

<u>where:</u>	ER =	emission rate (lbs per period)
	EF =	full load pollutant specific emission factor (lb/1000 gallons)
	EHP =	engine max rated horsepower (bhp)
	BSFC =	engine brake specific fuel consumption (gal/bhp-hr)
	EL =	engine load factors (percent of max fuel consumption)
	TM =	time in mode (hours/period)

The calculations for the auxiliary engines are similar, except that a 50 percent engine load factor for the generators is utilized. Compliance with the main engine controlled emission rates is assessed through emission source testing). Ongoing compliance will be assessed through implementation of the most current District-approved Boat Monitoring and Reporting Plan.

In addition, a permanently assigned emergency response vessel (i.e., the *Clean Seas II*) is associated with Platform Heritage along with a small ExxonMobil owned boom boat (the *MonArk*). The engines on these vessels are uncontrolled. The total engine horsepower, including auxiliary engines, is 1,770 bhp. Emissions liability is assigned in a prorated fashion among the eleven OCS platforms that utilize the vessel off the Santa Barbara coast. Emission factors, calculations and compliance procedures are the same as for the spot-charter supply vessels discussed above. If used, other emergency response boat fuel usage (and resulting emissions) shall be assessed against this emissions category.

4.5. **Sulfur Treating/Gas Sweetening Unit**

Platform Heritage is equipped with a methyl diethanolamine gas sweetening unit. The purpose of this unit is to remove hydrogen sulfide from the produced gas for use in the central process heater and the flare purge and pilot. The maximum treating capacity of this unit is 1.5 MMscfd at 1.5 percent H₂S (or 0.75 MMscfd at 3.0 percent H₂S). This is adequate to supply the flare purge and pilot (445 scfh) and the central process heater maximum fuel requirement (650,000 scfh). The acid gas from this system is recycled to the STV compressors. This system is equipped with a Houston Atlas H₂S analyzer and process controls to ensure that compliance with Rules 311 and 359 is achieved, as well as the permit limit of 30 ppmv H₂S.

4.6. **Tanks/Vessels/Sumps/Separators**

- 4.6.1 **Tanks:** Platform Heritage has one diesel fuel storage tank, a drilling deck drains settling tank and several chemical storage tote tanks (e.g., corrosion inhibitor storage tank, methanol storage tank, etc) of various sizes (250-1500 gallons each). The portable tote tanks are used in lieu of 55-gallon drums to deliver various chemicals to the platform including xylene, de-emulsifiers, corrosion inhibitors, and anti-foam. The diesel storage tank services the various IC engines on the platform and is not controlled. All these tank emissions are very small and are assumed to be

less than 0.10 tpy (200 lb/yr). The detailed tank calculations for compliance will be performed using the methods presented in USEPA AP-42, Chapter 7.

The drill deck drains settling tank collect liquids from the drill deck and the wellbay sump and separates the solids from liquids and oil from water. The oil is routed to the open drain sump and the water to the skim pile. The skim pile vessel is covered but not connected to the vapor gathering system.

- 4.6.2 Vessels: Platform Heritage has many pressure vessels (e.g., production separators, a test separator, clean-up separator, test treater, emulsion surge tank, vent scrubber, and suction scrubbers). All pressure vessels are connected to the platform's gas gathering system. All PSVs are connected to the flare relief system header. Emissions from pressure vessels are a result of fugitive hydrocarbon leaks from valves and connections.
- 4.6.3 Sumps: There is an open and closed drain sump, a skim pile, amine sump and a wellbay drain sump on the platform. The closed drain sump and the amine sump are connected to the vapor recovery system. The remaining tanks are covered.

The tank and sump tank emissions are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California*, January 1983). The calculation is:

$$ER = \left[\left(\frac{EF * SAREA}{24} \right) * CE * HPP \right]$$

where: ER = emission rate (lb/period)
 EF = ROC emission factor (lb/ft²-day)
 SAREA = unit surface area (ft²)
 CE = control efficiency
 HPP = operating hours per time period (hrs/period)

The emission factors are documented in the District's P&P 6100.060. For open top tanks, no control efficiency is assigned. A leak free cover with PVRVs is approximately 85 percent efficient and hookup to vapor recovery is assigned a 95 percent control efficiency.

4.7. **Vapor Recovery Systems**

The platform vapor recovery system is equipped with one electrically driven 50 bhp A-C Compressor Corp. compressor (Model 10GB) with a design capacity of 0.5 MMscfd. The compressed vapors are routed to the STV compressor for sales, injection or gas lift. The following equipment is connected to the vapor recovery system: glycol still, amine sump, glycol sump, closed drain, compressor distance pieces, and STV compressor discharge. All remaining major vessels are vented to the flare header.

4.8. **Helicopters**

Platform Heritage is serviced by the AS-355-F-F1 Twinstar helicopter. The Twinstar is a twin engine, five passenger aircraft that is much smaller than the previously used Bell 212/412. The helicopter is primarily used for personnel transportation and emergencies. Each round trip usually originates and terminates at the Santa Barbara Airport and averages approximately forty-

five minutes. Emission factors in units of "lb/hr" for different types of helicopters have been established for each operating mode based on the particular turbine engine used. These modes (idle, climb, cruise, and descent) make up the total cycle time for each trip segment. For Platform Heritage, there are two identical trip segments (Santa Barbara Airport to Platform Heritage and Platform Heritage to the Santa Barbara Airport). The emission rate per trip segment is calculated as:

$$ER = \sum_{mode} (EF_{mode} * TIM)$$

where:

ER = Emission rate per trip segment (lb/segment)

EF = pollutant specific emission factor per mode (lb/engine-hr)

TIM = Time in Mode (hr)

From this data, a platform specific emission rate per trip segment is calculated. For platform Heritage, the one trip segment is simply doubled to obtain an emission rate per trip. Emission tracking will be accomplished by reporting the number of trips per helicopter.

4.9. **Other Emission Sources**

The following is a brief discussion of other emission sources on Platform Heritage:

- 4.9.1 Pigging: Pipeline pigging operations occur on the platform. These consist of an emulsion pipeline pig launcher to Platform Harmony and a produced gas pipeline pig launcher to Platform Harmony. The pig launchers are connected to either the VRS or the flare header and are depressurized to this system after each use. The small amount of emissions which remain are vented to the atmosphere. ExxonMobil has committed to maintain the remaining pressure at levels no greater than 1 psig. The calculation per time period is:

$$ER = V_1 * \rho * wt\% * EPP$$

where:

ER = emission rate (lb/period)

V₁ = volume of vessel (ft³)

ρ = density of vapor at actual conditions (lb/ft³)

wt % = weight percent ROC-TOC

EPP = pigging events per time period (events/period)

- 4.9.2 General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurs on Platform Heritage as part of normal daily operations and includes small cold solvent degreasing and wipe cleaning. Mass balance emission calculations are used assuming all the solvent used evaporates to the atmosphere. Additionally, there is one cold solvent degreasing unit located on Platform Heritage.
- 4.9.3 Surface Coating: Surface coating operations typically include normal touch up activities. Entire platform painting programs are performed once every few years. Emissions are determined based on mass balance calculations assuming all solvents evaporate into the atmosphere. Emission of PM/PM₁₀ from paint overspray are not calculated due to the lack of established calculation techniques.

- 4.9.4 Abrasive Blasting: Abrasive blasting with CARB certified sands may be performed as a preparation step prior to surface coating. The engines used to power the two compressors are diesel driven. Particulate matter is emitted during this process. A general emission factor of 0.01 pound PM per pound of abrasive is used (SCAQMD - Permit Processing Manual, 1989) to estimate emissions of PM and PM₁₀. PM₁₀/ PM ratio of 1.0 is assumed.

4.10. *BACT/NSPS/NESHAP/MACT*

Except as described below, none of the emission units at Platform Heritage are subject to best available control technology (BACT), NSPS or NESHAP provisions. MACT provisions have yet to be promulgated.

BACT has been triggered pursuant to modifications authorized under ATC 9634 for the installation of a skid-mounted natural gas compressor unit and ATC 9099 for the Amine Fuel Gas System. As part of ATC 9828, ExxonMobil voluntarily implemented BACT controls on the Heritage/Harmony gas pipeline topsides project in order minimize their offset liability. Table 4.1 detail the BACT requirements for Platform Heritage.

Pursuant to Rule 331.E.1.b, all leaks from critical components are required to be replaced with BACT in accordance with the District's NSR rule. Table 4.2 details the Rule 331 BACT requirements for Platform Heritage.

Existing engines on the platform are subject to NESHAP ZZZZ. New engines on the platform are subject to NSPS IIII.

4.11. *CEMS/Process Monitoring/CAM*

- 4.11.1 CEMS: There are no in-stack continuous emission monitoring systems used on Platform Heritage to measure criteria pollutant emissions. However, a hydrogen sulfide analyzer is required to assess compliance with the fuel gas sulfur limits. This analyzer is classified as a CEM by the District and is subject to the Districts' CEM Protocol document (dated October 22, 1992 and any subsequent updates). This data does not have to be telemetered to the District. For most platform operations, process monitors (e.g., fuel meters) provide adequate data to assess compliance.

- 4.11.2 Process Monitoring: In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by the use of process monitoring systems. Examples of these monitors include: engine hour meters, fuel usage meters, water injection mass flow meters, flare gas flow meters and hydrogen sulfide analyzers. Once these process monitors are in place, it is important that they be well maintained and calibrated to ensure that the required accuracy and precision of the devices are within specifications. At a minimum, the following process monitors will be required to be operated, calibrated and maintained in good working order:

- Crane Engine Diesel Fuel Meter (if applicable)
- Supply Vessel Diesel Fuel Meters (main and auxiliary/bow thruster engines)
- Crew Vessel Diesel Fuel Meters (main and auxiliary engines)
- Flare Header Flow Meters
- Hour Meters (crane engine, emergency generator engines, firewater pump engines, compressor engines)
- Hydrogen Sulfide Analyzer

- Central Process Heater Fuel Meter

To implement the above calibration and maintenance requirements, a *Process Monitor Calibration and Maintenance Plan* was required of ExxonMobil. This Plan takes into consideration manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgement is utilized.

- 4.11.3 CAM: ExxonMobil – SYU Project is a major source that is subject to the USEPA’s Compliance Assurance Monitoring (CAM) rule (40 CFR 64). Any emissions unit at the facility with uncontrolled emissions potential exceeding major source emission thresholds for any pollutant is subject to CAM provisions. Currently no units at Platform Heritage are subject to a CAM Plan. The platform does not have any equipment, which uncontrolled would exceed 100 TPY of any criteria pollutant.

4.12. Source Testing/Sampling

Source testing and sampling are required in order to ensure compliance with permitted emission limits, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. Table 4.3 details the pollutants, test methods and frequency of required testing. ExxonMobil is required to follow the District *Source Test Procedures Manual* (May 24, 1990 and all updates). The following emission units are required to be source tested.

- Crane Engine
- Supply Boat Main Engines
- Crew Boat Main Engines
- Central Process Heater
- Cement Pump and Cuttings Reinjection Pump Engines (if triggered by Rule 333. I.8)

At a minimum, the process streams below are required to be sampled and analyzed on an annual basis. Duplicate samples are required:

- Produced Gas: Sample taken at production separator outlet. Analysis for: HHV, total sulfur, hydrogen sulfide, and composition.
- Fuel Gas: Sample taken at fuel gas header. Analysis for: HHV, total sulfur, hydrogen sulfide, and composition.
- Produced Oil: Sample taken at outlet from the production separator. Analysis for: API gravity; true vapor pressure (per Rule 325 methods).

All sampling and analyses are required to be performed according to District approved procedures and methodologies. Typically, the appropriate ASTM methods are acceptable. It is important that all sampling and analysis be traceable by chain of custody procedures. ExxonMobil’s source test plan shall include the specific sampling and analytical methods required to obtain the process stream data above.

Table 4.1 BACT Requirements for Specific Systems

Component Type	Technology	Performance Standard	System Subject to Emission Control Requirements
<i>Valves</i>	Low Emission Design Valves (e.g., bellows seal valves, valves with graphite or Teflon packing, machined stems or “stem finish”, injectable valve stem packing with Teflon or graphite rings).	100 ppm as methane above ambient, monitored per EPA Reference Method 21.	*Gas Compressor Skid Unit No. CZZ-306 *ATC 9828 Topsides Installation
	NSPS KKK standards apply	1000 ppm as methane above ambient, monitored per EPA Reference Method 21.	*Amine Fuel Gas Treating System
<i>Connectors (Flanges/Connections)</i>	Flanges: graphitic gaskets rated at 150% of actual process pressure and process temperature; Non-flange connections: none specified.	100 ppm as methane above ambient, monitored per EPA Reference Method 21.	*Gas Compressor Skid Unit No. CZZ-306 *ATC 9828 Topsides Installation
	NSPS KKK standards apply	1000 ppm as methane above ambient, monitored per EPA Reference Method 21.	*Amine Fuel Gas Treating System
<i>Compressor Seals</i>	Each compressor cylinder is equipped with two sealed compartment distance pieces which surround the reciprocating compressor cylinder’s power-shaft. The inner distance piece is purged with blanket gas and connected to vapor recovery; the outer distance piece is connected to the flare, with no supplemental blanket gas purge. The outer distance piece has an atmospheric seal system surrounding the reciprocating power-shaft.	100 ppm as methane above ambient, monitored per EPA Reference Method 21, if possible to monitor.	Gas Compressor Skid Unit No. CZZ-306
	NSPS KKK standards apply	1000 ppm as methane above ambient, monitored per EPA Reference Method 21.	*Amine Fuel Gas Treating System
<i>Relief Valves</i>	Routed to vapor recovery or flare.	Vapor recovery or flare/thermal oxidation system to have a capture/destruction efficiency of $\geq 98\%$ by weight.	Gas Compressor Skid Unit No. CZZ-306
	NSPS KKK standards apply	500 ppm as methane above ambient, monitored per EPA Reference Method 21.	*Amine Fuel Gas Treating System

Component Type	Technology	Performance Standard	System Subject to Emission Control Requirements
<i>Repairs Timelines</i>	Repairs to any BACT valve, flange/connection or compressor seal (if monitoring possible) showing between 100 ppm and 10,000 ppm above ambient to be made on the schedule detailed in Rule 331 for minor leaks. Repairs to any BACT valve, flange/connection or compressor seal (if monitoring possible) showing above 10,000 ppm above ambient to be made on the schedule(s) detailed in Rule 331.		*Gas Compressor Skid Unit No. CZZ-306
			*ATC 9828 Topsides Installation
			*Amine Fuel Gas Treating System
<i>Fugitive I&M Program</i>	Leak detection and repair program consistent with the requirements of the <i>Fugitive Hydrocarbon Emissions Components</i> Condition of this permit.		*Gas Compressor Skid Unit No. CZZ-306
			*ATC 9828 Topsides Installation
			*Amine Fuel Gas Treating System

Table 4.2 Rule 331 BACT Requirements for Specific Components

Tag No.	Component Type	Component Location	Plant/P&ID	BACT Install Date	BACT Performance Standard
HE-10344	Valve	Stem on 3" flanged choke valve (FV-726) on injection gas line to HE-2	HE-X11	4/31/1995	100 ppmv
HE-1871	Valve	Fisher 4" flanged valve level device for flow control on line from MBD-121 to MBA-194. Low emissions packing design.	HE-X39	2/13/1996	100 ppmv
HE-1877	Flange	Flange on top of valve at depropanizer	HE-X39	3/9/1997	100 ppmv
HE-20041	Valve	3" shutdown Ball valve in GHX gas service at compressor CZZ-306 N. cylinder. Low emissions packing design.	HE-X42	2/22/1999	100 ppmv
HE-20827	Valve	Ball valve on SA-6 Gas Lift Header	HE-X11A	10/19/2003	100 ppmv
HE-3728	Valve	4" level control valve LV 121 serving MBD 124	HE-X39	7/30/1998	100 ppmv
HE-5403	Valve	2" Ball valve BAX 101 packing on main gas lift header to HE-02 well.	HE-X-1102	7/30/1998	100 ppmv
HE-5419	Valve	4" flanged AOV 707-2 wellbay diverter ball valve (FMC, formerly National Oil Well) API 3000 in sour service on production line from well HE-5 manifold in cellar deck mezzanine (west end); stem packing leak. Max allow work pressure 6000 psig at operating	HE-X11	3/9/1997	100 ppmv
HE-5522	Valve	Plunger assembly on the 4" AOV 743-2 wellbay diverter valve on production line from well HE-1. Low emissions packing design.	HE-X11	1/21/1996	100 ppmv
HE-5640	Valve	Seal on 3" Apollo ANSI 600 class ball valve on bypass line around PSV-362 off of pump PBA-362 (depropanizer bottoms pump).	HE-X40	11/27/1996	Approved 11/27/96 to remove from service.
HE-7142	Compressor Seal	Gaskets between cylinder #2 and first distance piece on main gas compressor (CZZ-303). Gasket rated at 150% of actual process pressure at process temperature.	HE-X93	8/29/1995	100 ppmv
HE-7702	Valve	Packing on PSV-310-1 & BDV 310-2 bypass.	HE-X45	3/10/2001	100 ppmv
HE-7748	Valve	East flange on 6" orbit valve in sour service on the discharge line from the injection gas compressor CZZ-310 going from the discharge of the compressor to the injection gas cooler system. Low emissions packing design.	HE-X45	4/12/1996	100 ppmv
HE-7842	Valve	Stem packing leak on 2" blowdown valve #311-2 (Argus ball valve) on blowdown gas line from compressor CZZ-311. Low emissions packing design.	HE-X45	8/29/1995	100 ppmv
HE-7961	Compressor Seal	On injection gas compressor CZZ-311 Cyl. #1 discharge valve cover. Low emission compressor seal design.	HE-X45	11/16/1998	100 ppmv

Tag No.	Component Type	Component Location	Plant/P&ID	BACT Install Date	BACT Performance Standard
HE-7962	Compressor Seal	On injection gas compressor CZZ-311 Cyl. #2 discharge valve cover. Low emission compressor seal design.	HE-X45	11/16/1998	100 ppmv
HE-7963	Other	Compressor CZZ-311 at cover plate at bottom of cyl. 3.	HE-X45	11/11/1996	
HE-828	Other	1" Thr. Pipe Connection off of main gas compressor (stripping gas line to glycol regeneration section)	HE-X37	5/2/1995	100 ppmv
HE-8328	Valve	Ball valve packing on HE-7 Gas Lift Header	HE-X1145	10/19/2003	100 ppmv
HE-8435	Valve	Packing on 4" Ball valve south of control panel upper mezzanine cellar. Low emission packing design.	HE-X14	8/19/1998	100 ppmv
HE-8435	Valve	Block valve packing leak on G/L Manifold System	HE-X14	10/19/2003	100 ppmv
HE-8541	Valve	Ball valve on gas lift line to Heritage wells 741-760	HE-X15	2/23/2000	100 ppmv
HE-9577	Valve	Packing on HE-13 Gas Lift Header on PT-746-2	HE-X1148	1/8/2001	100 ppmv

Table 4.3 Source Test Requirements

SOURCE TEST REQUIREMENTS			
Emission & Limit Test Points	Pollutants	Parameters^(b)	Test Methods^{(a),(c)}
Crane Engines, Crew Boat Main Engines, Supply Boat Main Engines, Central Process Heater, Cement Pump Engines, & Cutting Reinjection Engine	NO _x	ppmv, lb/hr	EPA Method 7E, ARB 1-100
	ROC	ppmv, lb/hr	EPA Method 18
	CO	ppmv, lb/hr	EPA Method 10, ARB 1-100
	Sampling Point Det. Stack Gas Flow Rate O ₂ Moisture Content	Dry, Mol. Wt	EPA Method 1 EPA Method 2 or 19 EPA Method 3 EPA Method 4
Fuel Gas	Fuel Gas Flow Rate Higher Heating Value Total Sulfur Content ^(d)	BTU/scf	Fuel Gas Meter ^(f) ASTM D 1826-88 ASTM D 1072

Notes:

(a) All emissions tests to consist of three 40-minute runs. Crane engine tests to consist of three 20-minute runs performed at maximum safe load. Crew and supply boat main engines to be tested at cruise load. Crew boat test runs may be shortened based on prior approval by the APCD. The engine RPM and boat speed shall be recorded during each test run.

(b) The specific project crew and supply boat to be tested shall be determined by the APCD.

(c) USEPA methods 1-4 to be used to determine O₂, dry MW, moisture content, CO₂, and stack flow rate. Alternatively, USEPA 19 may be used to determine stack flow rate.

(d) SO_x emissions to be determined by mass balance calculation.

(e) The main engines from one crew and one supply boat shall be tested annually. The crane engine and central process heater shall be tested biennially.

(f) Procedures to obtain the required operating loads shall be clearly defined in the source test plan.

(g) Source tests on the cement pumps and the cutting reinjection pump are only required if triggered by Rule 333.I.8.

5.0 Emissions

5.1. General

Emissions calculations are divided into "permitted" and "exempt" categories. Permit exempt equipment is determined by District Rule 202. The permitted emissions for each emissions unit is based on the equipment's potential-to-emit (as defined by Rule 102). Section 5.2 details the permitted emissions for each emissions unit. Section 5.3 details the overall permitted emissions for the facility based on reasonable worst-case scenarios using the potential-to-emit for each emissions unit. Section 5.4 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301. Section 5.5 provides the estimated emissions from permit exempt equipment and also serves as the Part 70 list of insignificant emission. Section 5.6 provides the net emissions increase calculation for the facility and the stationary source. In order to accurately track the emissions from a facility, the District uses a computer database. Attachment 10.3 contains the District's documentation for the information entered into that database.

5.2. Permitted Emission Limits – Emission Units

Each emissions unit associated with the facility was analyzed to determine the potential-to-emit for the following pollutants:

- Nitrogen Oxides (NO_x)²
- Reactive Organic Compounds (ROC)
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x)³
- Particulate Matter (PM)⁴
- Particulate Matter smaller than 10 microns (PM₁₀)

Permitted emissions are calculated for both short term (hourly and daily) and long term (quarterly and annual) time periods. Section 4.0 (Engineering Analysis) provides a general discussion of the basic calculation methodologies and emission factors used. The reference documentation for the specific emission calculations may be found in Section 4 and Attachment 10.1. Table 5.1 provides the basic operating characteristics. Table 5.2 provides the specific emission factors. Tables 5.3 and 5.4 shows the permitted short-term and permitted long-term emissions for each unit or operation. In the table, the last column indicates whether the emission limits are federally enforceable. Those emissions limits that are federally enforceable are indicated by the symbol "FE". Those emissions limits that are District-only enforceable are indicated by the symbol "A". Emissions data that are shown for informational purposes only are not enforceable (District or federal) and are indicated by the symbol "NE".

² Calculated and reported as nitrogen dioxide (NO₂)

³ Calculated and reported as sulfur dioxide (SO₂)

⁴ Calculated and reported as all particulate matter smaller than 100 µm

5.3. **Permitted Emission Limits – Facility Totals**

The total potential-to-emit for all emission units associated with the facility was analyzed. This analysis looked at the reasonable worst-case operating scenarios for each operating period. The equipment operating in each of the scenarios is revised from the previous Part 70/PTO 9102 to account for the new Tier II engines for the *M/V Broadbill*. Unless otherwise specified, the operating characteristics defined in Table 5.1 for each emission unit are assumed. Table 5.5, shows the total permitted emissions for the facility. The total permitted quarterly and annual emissions for the facility are decreased based on the *M/V Broadbill* being operated forty percent (40%) of the annual total DPV crew boat usage. Fugitive hydrocarbon emissions have also increased due to ExxonMobil adding previously de minimis components to the permitted equipment list.

Hourly and Daily Scenarios:

- Pedestal crane engine
- Firewater Pump Engines
- Emergency Generator Engine
- Cement Pump and Cuttings Reinjection Pump Engines
- Emergency Drilling Engine
- Central Process Heater
- Flare Purge and pilot
- Planned continuous flaring (minus the purge/pilot volumes)
- Spot charter uncontrolled crew and supply boats
- Generator engines on crew and supply boats provide half of maximum engine rating
- Bow thruster on supply boat does not operate during peak hour
- Survival Capsule Engines
- Fugitive components
- Oil pig launcher/receivers
- Gas pig launcher/receiver
- Open/Closed drain sumps, wellbay sump, skim pile, amine sump
- Drill deck settling tank, chemical storage tote tanks
- Solvent usage
- Degreaser usage

Quarterly and Annual Scenario:

- Pedestal crane engine
- Firewater Pump Engines
- Emergency Generator Engine
- Cement Pump and Cuttings Reinjection Pump Engines
- Emergency Drilling Engine
- Central process heater
- Flare Purge and pilot
- Planned continuous flaring
- Planned intermittent (other) flaring
- Unplanned flaring
- Fugitive components

- Controlled and uncontrolled (spot-charter) supply boats
- Generator engines on crew and supply boats provide half of maximum engine rating
- Bow thruster on supply boat
- Controlled and uncontrolled (spot-charter) crew boats
- Survival Capsule Engines
- Oil pig launcher/receivers
- Gas pig launcher/receiver
- Open/Closed drain sumps, wellbay sump, skim pile, amine sump
- Drill deck settling tank, chemical storage tote tanks
- Solvent usage
- Degreaser usage

5.4. *Part 70: Federal Potential to Emit for the Facility*

Table 5.6 lists the federal Part 70 potential to emit. Being subject to the OCS Air Regulation, all project emissions, except fugitive emissions, are counted in the federal definition of potential to emit. However, fugitives are counted in the Federal PTE if the facility is subject to any applicable NSPS or NESHAP requirement.

5.5. *Exempt Emission Sources/Part 70 Insignificant Emissions*

Equipment/activities exempt pursuant to Rule 202 include maintenance operations involving surface coating. Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. The following emission units are exempt from permit per Rule 202, but are not considered insignificant emission units, since these exceed the insignificant emissions threshold.

Table 5.7 presents the estimated annual emissions from these exempt equipment items, including those exempt items not considered insignificant. This permit includes the Solvents/Surface coating activities during maintenance operations.

5.6. *Net Emissions Increase Calculation*

The net emissions increase (NEI) for Platform Heritage is equal to the existing facility NEI plus any emissions increase ("I") due to past projects. This facility's contribution to the stationary source's net emissions increase since November 15, 1990 (the day the federal Clean Air Act Amendments were adopted) is based on the NSR permit actions since December 5, 1991, as is stated in Table 5.8. The NEI for the ExxonMobil – SYU stationary sources is found in Table 10.3. This renewal incorporates ATC/PTO 13041 which converts 3.175 lbs ROC/day from previously *de minimis* fugitive hydrocarbon components to NEI.

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Table 5.1 Operating Equipment Description

Equipment Item	Description			Device Specifications				Usage Data			Maximum Operating Schedule				References
		Exxon ID #	APCD DeviceNo	Fuel	%S	Size	Units	Capacity	Units	Load	hr	day	qtr	year	
Stationary Internal Combustion Engines (Table A)	Pedestal Crane East	ZZZ-507	5350	D2	0.0015	450	bhp	6,480	Btu/bhp-hr	--	1	24	1,095	4,380	A
	Emergency Production Generator	ZAN-515	5371	D2	0.0015	1344	bhp	6,480	Btu/bhp-hr	--	1	2	200	200	
	Firewater Pump	PBE-357	5372	D2	0.0015	400	bhp	6,480	Btu/bhp-hr	--	1	2	200	200	
	Firewater Pump	PBE-367	7143	D2	0.0015	525	bhp	6,480	Btu/bhp-hr	--	1	2	200	200	
	Emergency Drilling Engine	ZAN-515	5370	D2	0.0015	2307	bhp	8,200	Btu/bhp-hr	--	1	2	200	200	
	B - Side Cement Pumping Skid		112508	D2	0.0015	500	bhp	7,500	Btu/bhp-hr	--	1	24	2,190	8,760	
	C - Side Cement Pumping Skid		112507	D2	0.0015	500	bhp	7,500	Btu/bhp-hr	--	1	24	2,190	8,760	
	Cuttings Reinjection Pump		112509	D2	0.0015	450	bhp	7,500	Btu/bhp-hr	--	1	24	2,190	8,760	
Combustion - External	Central Process Heater	EAP-603	5353	PG	0.0030	27.2	MMBtu/hr	--	--	--	1	24	2,190	8,760	B
	Central Process Heater (PR)	EAP-603	5353	PR	0.0165	27.2	MMBtu/hr	--	--	--	1	6	80	320	
Flare Relief System (Table J)	Purge and Pilot		102382	PG	0.0030	445	scfh	0.579	MMBtu/hr	--	1	24	2,190	8,760	C
	Planned - Continuous		102383	SG	2.0000	607	scfh	0.789	MMBtu/hr	--	1	24	2,190	8,760	
	Planned - Other		102384	SG	2.0000	3,820	MMBtu/hr	6.300	MMscf/yr	--	--	--	0	1	
	Unplanned		102385	SG	2.0000	3,820	MMBtu/hr	34.000	MMscf/yr	--	--	--	0	1	
Fugitive Components - Gas															
Valve/Connection	Accessible		102526	--	--	7,679	comp-lp	--	--	--	1	24	2,190	8,760	D
Valve/Connection	Category B		102527	--	--	6,112	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Category C		104948	--	--	488	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Category F		104943	--	--	3,168	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Unsafe		102529	--	--	81	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Exempt		102536	--	--	25	comp-lp	--	--	--	1	24	2,190	8,760	
						sub-total =	17,553								
Fugitive Components - Oil															
Valve/Connection	Accessible		102516	--	--	11,507	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Category B		102520	--	--	55	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Category F		102517	--	--	1,345	comp-lp	--	--	--	1	24	2,190	8,760	
Valve/Connection	Unsafe		104950	--	--	5	comp-lp	--	--	--	1	24	2,190	8,760	
Pump Seal	Dual/Tandem		102518	--	--	6	comp-lp	--	--	--	1	24	2,190	8,760	
	Exempt		102525	--	--	20	comp-lp	--	--	--	1	24	2,190	8,760	
						sub-total =	12,938								

Equipment Item	Description			Device Specifications				Usage Data		Load	Maximum Operating Schedule				References
		Exxon ID #	APCD DeviceNo	Fuel	%S	Size	Units	Capacity	Units		hr	day	qtr	year	
Supply Boat	Main Engine - DPV		5357	D2	0.0015	4,000	bhp-total	0.055	gal/bhp-hr	0.65	1	22	422	1,687	E
	Main Engine - Spot Charter		104959	D2	0.0015	4,000	bhp-total	0.055	gal/bhp-hr	0.65	1	22	42	169	
	Generator Engine - DPV		5358	D2	0.0015	400	bhp-total	0.055	gal/bhp-hr	0.50	1	22	534	2,137	
	Bow Thruster - DPV		5359	D2	0.0015	500	bhp-total	0.055	gal/bhp-hr	1.00	1	3	73	291	
	Winch - DPV		104962	D2	0.0015	409	bhp-total	0.055	gal/bhp-hr	1.00	1	3	73	291	
	Emergency Response		5360	D2	0.0015	1,770	bhp-total	0.055	gal/bhp-hr	0.65	--	--	51	202	
Survival Capsules	Survival Capsule #1	ZZZ-514	103956	D2	0.0015	55	bhp	0.055	gal/bhp-hr	0.40	1	24	50	200	
	Survival Capsule #2	ZZZ-513	103957	D2	0.0015	55	bhp	0.055	gal/bhp-hr	0.40	1	24	50	200	
	Survival Capsule #3	ZZZ-509	103958	D2	0.0015	30	bhp	0.055	gal/bhp-hr	0.40	1	24	50	200	
Crew Boat	Main Engine - DPV		5361	D2	0.0015	3,860	bhp-total	0.055	gal/bhp-hr	0.85	1	22	197	790	F
	Main Engines - DPV Broadbill		107900	D2	0.0015	2,400	bhp-total	0.055	gal/bhp-hr	0.85	1	22	212	847	
	Main Engine - Spot Charter		104960	D2	0.0015	3,860	bhp-total	0.055	gal/bhp-hr	0.85	1	22	33	132	
	Auxiliary Engine - DPV		5362	D2	0.0015	262	bhp-total	0.055	gal/bhp-hr	0.50	1	22	840	3,360	
	Auxiliary Engine - DPV Broadbill		107901	D2	0.0015	124	bhp-total	0.055	gal/bhp-hr	0.50	1	22	1,183	4,733	
Pigging Equipment (Table F)	Emulsion Pig Launcher	KAH-791	102539			48	acf	1	psig		1	5	40	175	G
	Gas Pig Launcher	KAH-793	102540			20	acf	1	psig		1	5	26	104	
Sumps (Table N)	Closed Drain Sump	MBH-132	5363	--	--	90	ft2	--	--	--	1	24	2,190	8,760	H
	Open Drain Sump	ABH-406	5364	--	--	90	ft2	--	--	--	1	24	2,190	8,760	
	Wellbay Drain Sump	ABH-405	5365	--	--	90	ft2	--	--	--	1	24	2,190	8,760	
	Amine Sump	MBH-170	5366	--	--	42	ft2	--	--	--	1	24	2,190	8,760	
	Skim Pile	ABH-416	5367	--	--	16	ft2	--	--	--	1	24	2,190	8,760	
Storage Tanks (Table C-1)	Drilling Settling Tank	ABJ-417	5368	--	--	200	ft2	--	--	--	1	24	2,190	8,760	
	Chemical Storage Tote Tanks		102381	--	--	varies	gal	--	--	--	1	24	2,190	8,760	
Solvent Usage	Cleaning/degreasing		5369	--	--	various		various	--	--	1	24	2,190	8,760	I

Table 5.2 Equipment Emission Factors

Equipment Item	Description			Emission Factors								References
		Exxon ID #	APCD DeviceNo	NOx	ROC	CO	SOx	PM	PM10	GHG	Units	
Stationary Internal Combustion Engines (Table A)	Pedestal Crane East	ZZZ-507	5350	2.696	0.302	0.950	0.0015	0.310	0.310	163.600	lb/MMBtu	A
	Emergency Production Generator	ZAN-515	5371	14.061	1.120	3.030	0.0045	1.000	1.000	556.580	g/bhp-hr	
	Firewater Pump	PBE-357	5372	14.061	1.120	3.030	0.0045	1.000	1.000	556.580	g/bhp-hr	
	Firewater Pump	PBE-367	7143	14.061	1.120	3.030	0.0045	1.000	1.000	556.580	g/bhp-hr	
	Emergency Drilling Engine	ZAN-515	5370	14.061	1.120	3.030	0.0057	1.000	1.000	556.580	g/bhp-hr	
	B - Side Cement Pumping Skid		112508	2.80	0.20	2.600	0.0052	0.150	0.150	556.580	g/bhp-hr	
	C - Side Cement Pumping Skid		112507	2.80	0.20	2.600	0.0052	0.150	0.150	556.580	g/bhp-hr	
	Cuttings Reinjection Pump		112509	2.80	0.20	2.600	0.0052	0.150	0.150	556.580	g/bhp-hr	
Combustion - External	Central Process Heater	EAP-603	5353	0.036	0.0054	0.297	0.004	0.0075	0.0075	117.0000	lb/MMBtu	B
	Central Process Heater (PR)	EAP-603	5353	0.036	0.0054	0.297	0.011	0.0075	0.0075	117.0000	lb/MMBtu	
Flare Relief System (Table J)	Purge and Pilot		102382	0.068	0.12	0.37	0.004	0.020	0.020	117.0000	lb/MMBtu	C
	Planned - Continuous		102383	0.068	0.12	0.37	2.600	0.020	0.020	117.0000	lb/MMBtu	
	Planned - Other		102384	0.068	0.12	0.37	2.600	0.020	0.020	117.0000	lb/MMBtu	
	Unplanned		102385	0.068	0.12	0.37	2.600	0.020	0.020	117.0000	lb/MMBtu	
Fugitive Components - Gas												
Valve/Connection	Accessible		102526	--	0.0147	--	--	--	--	--	lb/day-clp	D
Valve/Connection	Category B		102527	--	0.0110	--	--	--	--	--	lb/day-clp	
Valve/Connection	Category C		104948	--	0.0096	--	--	--	--	--	lb/day-clp	
Valve/Connection	Category F		104943	--	0.0074	--	--	--	--	--	lb/day-clp	
Valve/Connection	Unsafe		102529	--	0.0736	--	--	--	--	--	lb/day-clp	
Valve/Connection	Exempt		102536	--	0.0000	--	--	--	--	--	lb/day-clp	
Fugitive Components - Oil												
Valve/Connection	Accessible		102516	--	0.0009	--	--	--	--	--	lb/day-clp	D
Valve/Connection	Category B		102520	--	0.0007	--	--	--	--	--	lb/day-clp	
Valve/Connection	Category F		102517	--	0.0004	--	--	--	--	--	lb/day-clp	
Valve/Connection	Unsafe		104950	--	0.0044	--	--	--	--	--	lb/day-clp	
Pump Seal	Dual/Tandem		102518	--	0.0000	--	--	--	--	--	lb/day-clp	
	Exempt		102525	--	0.0000	--	--	--	--	--	lb/day-clp	

Equipment Item	Description			Emission Factors								References
		Exxon ID #	APCD DeviceNo	NOx	ROC	CO	SOx	PM	PM10	GHG	Units	
Supply Boat ^{1, 2}	Main Engine - DPV		5357	337.00	16.80	78.30	0.2073	33.00	31.68	22309.60	lb/1000 gal	E
	Main Engine - Spot Charter		104959	561.00	16.80	78.30	0.2073	33.00	31.68	22309.60	lb/1000 gal	
	Generator Engine - DPV		5358	600.00	49.00	129.30	0.2073	42.20	40.51	22309.60	lb/1000 gal	
	Bow Thruster - DPV		5359	600.00	49.00	129.30	0.2073	42.20	40.51	22309.60	lb/1000 gal	
	Winch - DPV		104962	600.00	49.00	129.30	0.2073	42.20	40.51	22309.60	lb/1000 gal	
	Emergency Response		5360	561.17	16.80	44.60	0.2073	33.00	31.68	22309.60	lb/1000 gal	
Survival Capsules	Survival Capsule #1	ZZZ-514	103956	561.17	17.10	78.30	0.2073	33.00	31.68	22309.60	lb/1000 gal	
	Survival Capsule #2	ZZZ-513	103957	561.17	17.10	78.30	0.2073	33.00	31.68	22309.60	lb/1000 gal	
	Survival Capsule #3	ZZZ-509	103958	561.17	17.10	78.30	0.2073	33.00	31.68	22309.60	lb/1000 gal	
Crew Boat ^{1, 2}	Main Engine - DPV		5361	336.70	17.10	80.90	0.2073	33.00	31.68	22309.60	lb/1000 gal	F
	Main Engines - DPV Broadbill		104960	218.98	17.10	80.90	0.2073	5.93	5.93	22309.60	lb/1000 gal	
	Main Engine - Spot Charter		5362	561.17	17.10	80.90	0.2073	33.00	31.68	22309.60	lb/1000 gal	
	Auxiliary Engine - DPV			600.05	48.98	129.26	0.2073	42.18	40.49	22309.60	lb/1000 gal	
	Auxiliary Engine - DPV Broadbill			217.87	48.98	129.26	0.2073	5.93	5.93	22309.60	lb/1000 gal	
Pigging Equipment (Table F)	Emulsion Pig Launcher	KAH-791	102539	--	0.018	--	--	--	--	--	lb/acf-evt	G
	Gas Pig Launcher	KAH-793	102540	--	0.018	--	--	--	--	--	lb/acf-evt	
Sumps (Table N)	Closed Drain Sump	MBH-132	5363	--	0.001	--	--	--	--	--	lb/ft ² -day	H
	Open Drain Sump	ABH-406	5364	--	0.002	--	--	--	--	--	lb/ft ² -day	
	Wellbay Drain Sump	ABH-405	5365	--	0.002	--	--	--	--	--	lb/ft ² -day	
	Amine Sump	MBH-170	5366	--	0.001	--	--	--	--	--	lb/ft ² -day	
	Skim Pile	ABH-416	5367	--	0.002	--	--	--	--	--	lb/ft ² -day	
Storage Tanks (Table C-1)	Drilling Settling Tank	ABJ-417	5368	--	0.002	--	--	--	--	--	lb/ft ² -day	
	Chemical Storage Tote Tanks		102381	--	0.100	--	--	--	--	--	tons per year	
Solvent Usage	Cleaning/degreasing		5369	--	various	--	--	--	--	--	lb/gal	I

Notes:

¹ For emission calculations and fuel use reporting, the main engines on dedicated project vessels are treated as controlled engines.

² For emission calculations and fuel use reporting, all spot charter vessels are treated as uncontrolled engines.

Table 5.3 Hourly and Daily Emissions

Equipment Item	Description			NOx		ROC		CO		SOx		PM		PM10		GHG		Federal
		Exxon ID #	APCD DeviceNo	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	Enforceability
Stationary Internal Combustion Engines (Table A)	Pedestal Crane East	ZZZ-507	5350	8.33	200.00	0.93	22.37	2.94	70.47	0.00	0.11	0.96	23.00	0.96	23.00	505.68	12,136.35	FE
	Emergency Production Generator	ZAN-515	5371	41.66	83.33	3.32	6.64	8.98	17.96	0.01	0.03	2.96	5.93	2.96	5.93	1,649.13	3,298.25	FE
	Firewater Pump	PBE-357	5372	12.40	24.80	0.99	1.98	2.67	5.34	0.00	0.01	0.88	1.76	0.88	1.76	490.81	981.62	FE
	Firewater Pump	PBE-367	7143	16.27	32.55	1.30	2.59	3.51	7.01	0.01	0.01	1.16	2.31	1.16	2.31	644.19	1,288.38	FE
	Emergency Drilling Engine	ZAN-515	5370	71.52	143.03	5.70	11.40	15.41	30.82	0.03	0.06	5.09	10.17	5.09	10.17	2,830.75	5,661.51	FE
	B - Side Cement Pumping Skid		112508	3.09	74.07	0.22	5.29	2.87	68.78	0.01	0.14	0.17	3.97	0.17	3.97	613.51	14,724.34	FE
	C - Side Cement Pumping Skid		112507	3.09	74.07	0.22	5.29	2.87	68.78	0.01	0.14	0.17	3.97	0.17	3.97	613.51	14,724.34	FE
	Cuttings Reinjection Pump		112509	2.78	66.67	0.20	4.76	2.58	61.90	0.01	0.12	0.15	3.57	0.15	3.57	552.16	13,251.90	FE
Combustion - External	Central Process Heater	EAP-603	5353	0.98	23.50	0.15	3.52	8.08	193.88	0.11	2.55	0.20	4.90	0.20	4.90	3,182.40	76,377.60	FE
	Central Process Heater (PR)	EAP-603	5353	0.98	5.88	0.15	0.88	8.08	48.47	0.30	1.80	0.20	1.22	0.20	1.22	3,182.40	19,094.40	FE
Flare Relief System (Table J)	Purge and Pilot		102382	0.04	0.94	0.07	1.67	0.21	5.14	0.00	0.05	0.01	0.28	0.01	0.28	67.68	1,624.43	FE
	Planned - Continuous		102383	0.05	1.29	0.10	2.28	0.29	7.01	2.05	49.24	0.02	0.38	0.02	0.38	92.32	2,215.79	FE
	Planned - Other		102384	--	--	--	--	--	--	--	--	--	--	--	--	--	--	NE
	Unplanned		102385	--	--	--	--	--	--	--	--	--	--	--	--	--	--	NE
Fugitive Components - Gas																		
Valve/Connection	Accessible		102526	--	--	4.70	112.88	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Category B		102527	--	--	2.80	67.23	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Category C		104948	--	--	0.20	4.68	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Category F		104943	--	--	0.98	23.44	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Unsafe		102529	--	--	0.25	5.96	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Exempt		102536	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	NE
	Subtotal:					8.93	214.20											FE
Fugitive Components - Oil																		
Valve/Connection	Accessible		102516	--	--	0.432	10.36	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Category B		102520	--	--	0.002	0.04	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Category F		102517	--	--	0.022	0.54	--	--	--	--	--	--	--	--	--	--	NE
Valve/Connection	Unsafe		104950	--	--	0.001	0.02	--	--	--	--	--	--	--	--	--	--	NE
Pump Seal	Dual/Tandem		102518	--	--	0.000	0.00	--	--	--	--	--	--	--	--	--	--	NE
	Exempt		102525	--	--	0.000	0.00	--	--	--	--	--	--	--	--	--	--	NE
	Subtotal:					0.46	10.95											FE

Equipment Item	Description			NOx		ROC		CO		SOx		PM		PM10		GHG		Federal
		Exxon ID #	APCD DeviceNo	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	Enforceability
Supply Boat	Main Engine - DPV		5357	48.19	1,060.20	2.40	52.85	11.20	246.33	0.03	0.65	4.72	103.82	4.53	99.67	3,190.27	70,186.00	FE
	Main Engine - Spot Charter		104959	80.22	1,764.91	2.40	52.85	11.20	246.33	0.03	0.65	4.72	103.82	4.53	99.67	3,190.27	70,186.00	FE
	Generator Engine - DPV		5358	6.60	145.20	0.54	11.86	1.42	31.29	0.00	0.05	0.46	10.21	0.45	9.80	245.41	5,398.92	FE
	Bow Thruster - DPV		5359	16.50	49.50	1.35	4.04	3.56	10.67	0.01	0.02	1.16	3.48	1.11	3.34	613.51	1,840.54	FE
	Winch - DPV		104962	13.50	40.49	1.10	3.31	2.91	8.73	0.00	0.01	0.95	2.85	0.91	2.73	501.85	1,505.56	FE
	Emergency Response		5360	--	--	--	--	--	--	--	--	--	--	--	--	--	--	FE
Survival Capsules	Survival Capsule #1	ZZZ-514	103956	0.68	16.30	0.02	0.50	0.09	2.27	0.00	0.01	0.04	0.96	0.04	0.92	26.99	647.87	FE
	Survival Capsule #2	ZZZ-513	103957	0.68	16.30	0.02	0.50	0.09	2.27	0.00	0.01	0.04	0.96	0.04	0.92	26.99	647.87	FE
	Survival Capsule #3	ZZZ-509	103958	0.37	8.89	0.01	0.27	0.05	1.24	0.00	0.00	0.02	0.52	0.02	0.50	14.72	353.38	FE
Crew Boat	Main Engine - DPV		5361	60.76	1,318.48	3.09	66.96	14.60	316.79	0.04	0.81	5.96	129.22	5.72	124.05	4,025.88	87,361.57	FE
	Main Engine - DPV Broadbill		107900	24.57	540.54	1.92	42.21	9.08	199.69	0.02	0.51	0.67	14.63	0.67	14.63	2,503.14	55,069.02	FE
	Main Engine - Spot Charter		104960	101.27	2,197.46	3.09	66.96	14.60	316.79	0.04	0.81	5.96	129.22	5.72	124.05	4,025.88	87,361.57	FE
	Auxiliary Engine - DPV		5362	4.32	93.82	0.35	7.66	0.93	20.21	0.00	0.03	0.30	6.59	0.29	6.33	160.74	3,488.07	FE
	Auxiliary Engine - DPV Broadbill		107901	0.74	16.34	0.17	3.67	0.44	9.70	0.00	0.02	0.02	0.44	0.02	0.44	76.08	1,673.67	FE
Pigging Equipment (Table F)	Emulsion Pig Launcher	KAH-791	102539	--	--	0.87	4.33	--	--	--	--	--	--	--	--	--	--	FE
	Gas Pig Launcher	KAH-793	102540	--	--	0.36	1.80	--	--	--	--	--	--	--	--	--	--	FE
Sumps (Table N)	Closed Drain Sump	MBH-132	5363	--	--	0.002	0.057	--	--	--	--	--	--	--	--	--	--	FE
	Open Drain Sump	ABH-406	5364	--	--	0.007	0.170	--	--	--	--	--	--	--	--	--	--	FE
	Wellbay Drain Sump	ABH-405	5365	--	--	0.007	0.170	--	--	--	--	--	--	--	--	--	--	FE
	Amine Sump	MBH-170	5366	--	--	0.001	0.026	--	--	--	--	--	--	--	--	--	--	FE
	Skim Pile	ABH-416	5367	--	--	0.001	0.030	--	--	--	--	--	--	--	--	--	--	FE
Storage Tanks (Table C-1)	Drilling Settling Tank	ABJ-417	5368	--	--	0.016	0.378	--	--	--	--	--	--	--	--	--	--	FE
	Chemical Storage Tote Tanks		102381	--	--	0.023	0.550	--	--	--	--	--	--	--	--	--	--	FE
Solvent Usage	Cleaning/degreasing		5369	--	--	0.46	10.96	--	--	--	--	--	--	--	--	--	--	FE

Table 5.4 Quarterly and Annual Emissions

Equipment Item	Description			NOx		ROC		CO		SOx		PM		PM10		GHG		Federal	
		Exxon ID #	APCD DeviceNo	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	Enforceability	
Stationary Internal Combustion Engines (Table A)	Pedestal Crane East	ZZZ-507	5350	4.56	18.25	0.51	2.04	1.61	6.43	0.00	0.01	0.52	2.10	0.52	2.10	276.86	1,107.44	FE	
	Emergency Production Generator	ZAN-515	5371	4.17	4.17	0.33	0.33	0.90	0.90	0.00	0.00	0.30	0.30	0.30	0.30	164.91	164.91	FE	
	Firewater Pump	PBE-357	5372	1.24	1.24	0.10	0.10	0.27	0.27	0.00	0.00	0.09	0.09	0.09	0.09	49.08	49.08	FE	
	Firewater Pump	PBE-367	7143	1.63	1.63	0.13	0.13	0.35	0.35	0.00	0.00	0.12	0.12	0.12	0.12	64.42	64.42	FE	
	Emergency Drilling Engine	ZAN-515	5370	7.15	7.15	0.57	0.57	1.54	1.54	0.00	0.00	0.51	0.51	0.51	0.51	283.08	283.08	FE	
	B - Side Cement Pumping Skid		112508	3.38	13.52	0.24	0.97	3.14	12.55	0.01	0.03	0.18	0.72	0.18	0.72	671.80	2,687.19	FE	
	C - Side Cement Pumping Skid		112507	3.38	13.52	0.24	0.97	3.14	12.55	0.01	0.03	0.18	0.72	0.18	0.72	671.80	2,687.19	FE	
	Cuttings Reinjection Pump		112509	3.04	12.17	0.22	0.87	2.82	11.30	0.01	0.02	0.16	0.65	0.16	0.65	604.62	2,418.47	FE	
Combustion - External	Central Process Heater	EAP-603	5353	1.07	4.29	0.16	0.64	8.85	35.38	0.12	0.46	0.22	0.89	0.22	0.89	3,484.73	13,938.91	FE	
	Central Process Heater (PR)	EAP-603	5353	0.04	0.16	0.01	0.02	0.32	1.29	0.01	0.05	0.01	0.03	0.01	0.03	127.30	509.18	FE	
Flare Relief System (Table J)	Purge and Pilot		102382	0.04	0.17	0.08	0.31	0.23	0.94	0.00	0.01	0.01	0.05	0.01	0.05	74.11	296.46	FE	
	Planned - Continuous		102383	0.06	0.24	0.10	0.42	0.32	1.28	2.25	8.99	0.02	0.07	0.02	0.07	101.10	404.38	FE	
	Planned - Other		102384	0.06	0.26	0.12	0.50	0.38	1.54	2.70	10.79	0.02	0.08	0.02	0.08	121.44	485.75	FE	
	Unplanned		102385	0.35	1.39	0.61	2.46	1.89	7.55	13.26	53.04	0.10	0.41	0.10	0.41	596.70	2,386.80	FE	
Fugitive Components - Gas																			
Valve/Connection	Accessible		102526	--	--	5.15	20.60	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Category B		102527	--	--	3.07	12.27	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Category C		104948	--	--	0.21	0.85	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Category F		104943	--	--	1.07	4.28	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Unsafe		102529	--	--	0.27	1.09	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Exempt		102536	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	NE	
Subtotal:				9.77		39.09													FE
Fugitive Components - Oil																			
Valve/Connection	Accessible		102516	--	--	0.473	1.890	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Category B		102520	--	--	0.002	0.007	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Category F		102517	--	--	0.025	0.098	--	--	--	--	--	--	--	--	--	--	NE	
Valve/Connection	Unsafe		104950	--	--	0.001	0.004	--	--	--	--	--	--	--	--	--	--	NE	
Pump Seal	Dual/Tandem		102518	--	--	0.000	0.000	--	--	--	--	--	--	--	--	--	--	NE	
	Exempt		102525	--	--	0.000	0.000	--	--	--	--	--	--	--	--	--	--	NE	
Subtotal:				0.50		2.00													FE

Equipment Category	Description			NOx		ROC		CO		SOx		PM		PM10		GHG		Federal
		Exxon ID #	APCD DeviceNo	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	Enforceability
Supply Boat	Main Engine - DPV		5357	10.16	40.65	0.51	2.03	2.36	9.45	0.01	0.03	1.00	3.98	0.96	3.82	672.84	2691.34	FE
	Main Engine - Spot Charter		104959	1.69	6.77	0.05	0.20	0.24	0.94	0.00	0.00	0.10	0.40	0.10	0.38	67.28	269.13	FE
	sub-total =			11.86	47.42	0.56	2.23	2.60	10.39	0.01	0.03	1.09	4.38	1.05	4.20	740.12	2960.47	FE
	Generator Engine - DPV		5358	1.76	7.05	0.14	0.58	0.38	1.52	0.00	0.00	0.12	0.50	0.12	0.48	65.57	262.27	FE
	Bow Thruster - DPV		5359	0.60	2.40	0.05	0.20	0.13	0.52	0.00	0.00	0.04	0.17	0.04	0.16	22.35	89.41	FE
	Winch - DPV		104962	0.49	1.97	0.04	0.16	0.11	0.42	0.00	0.00	0.03	0.14	0.03	0.13	18.28	73.14	FE
	Emergency Response		5360	0.90	3.59	0.03	0.11	0.07	0.29	0.00	0.00	0.05	0.21	0.05	0.20	35.68	142.64	FE
	Survival Capsule #1	ZZZ-514	103956	0.02	0.07	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.67	2.70	FE
	Survival Capsule #2	ZZZ-513	103957	0.02	0.07	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.67	2.70	FE
	Survival Capsule #3	ZZZ-509	103958	0.01	0.04	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.37	1.47	FE
Crew Boat	Main Engine - DPV		5361	6.00	23.99	0.30	1.22	1.44	5.76	0.00	0.01	0.59	2.35	0.56	2.26	397.35	1589.42	FE
	Main Engine - DPV Broadbill		107900	2.60	10.40	0.20	0.81	0.96	3.84	0.00	0.01	0.07	0.28	0.07	0.28	264.90	1059.61	FE
	Main Engine - Spot Charter		104960	1.67	6.66	0.05	0.20	0.24	0.96	0.00	0.00	0.10	0.39	0.09	0.38	66.23	264.90	FE
	sub-total =			10.26	41.05	0.56	2.23	2.64	10.57	0.01	0.03	0.76	3.02	0.73	2.91	728.48	2913.93	FE
	Auxiliary Engine - DPV		5362	1.82	7.26	0.15	0.59	0.39	1.56	0.00	0.00	0.13	0.51	0.12	0.49	67.51	270.04	FE
	Auxiliary Engine - DPV Broadbill		107901	0.44	1.76	0.10	0.40	0.26	1.04	0.00	0.00	0.01	0.05	0.01	0.05	45.01	180.03	FE
	sub-total =			2.26	9.02	0.25	0.99	0.65	2.61	0.00	0.00	0.14	0.56	0.13	0.54	112.52	450.07	FE
	Emulsion Pig Launcher	KAH-791	102539	--	--	0.017	0.076	--	--	--	--	--	--	--	--	--	--	FE
	Gas Pig Launcher	KAH-793	102540	--	--	0.005	0.019	--	--	--	--	--	--	--	--	--	--	FE
	Closed Drain Sump	MBH-132	5363	--	--	0.003	0.010	--	--	--	--	--	--	--	--	--	--	FE
Sumps (Table N)	Open Drain Sump	ABH-406	5364	--	--	0.008	0.031	--	--	--	--	--	--	--	--	--	--	FE
	Wellbay Drain Sump	ABH-405	5365	--	--	0.008	0.031	--	--	--	--	--	--	--	--	--	--	FE
	Amine Sump	MBH-170	5366	--	--	0.001	0.005	--	--	--	--	--	--	--	--	--	--	FE
	Skim Pile	ABH-416	5367	--	--	0.001	0.006	--	--	--	--	--	--	--	--	--	--	FE
	Drilling Settling Tank	ABJ-417	5368	--	--	0.017	0.069	--	--	--	--	--	--	--	--	--	--	FE
Storage Tanks (Table C-1)	Chemical Storage Tote Tanks		102381	--	--	0.025	0.100	--	--	--	--	--	--	--	--	--	--	FE
Solvent Usage	Cleaning/degreasing		5369	--	--	0.50	2.00	--	--	--	--	--	--	--	--	--	--	FE
Notes:																		
FE = Federally enforceable																		
AE = APCD-only enforceable																		
NE = Not enforceable																		

Table 5.5 Total Permitted Facility Emissions

A. Hourly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	159.14	12.87	41.81	0.07	11.53	11.53	7,899.75
Combustion - External	0.98	0.15	8.08	0.30	0.20	0.20	3,182.40
Combustion - Flare	0.09	0.16	0.51	2.05	0.03	0.03	160.01
Fugitive Components	--	9.38	--	--	--	--	--
Supply Boat	100.32	4.04	15.53	0.04	6.13	5.89	3,937.53
Emergency Response	--	--	--	--	--	--	--
Survival Capsules	1.73	0.05	0.24	0.00	0.10	0.10	68.71
Crew Boat	105.59	3.44	15.53	0.04	6.26	6.01	4,186.62
Pigging	--	1.23	--	--	--	--	--
Sumps/Tanks/Separators	--	0.06	--	--	--	--	--
Solvent Usage	--	0.46	--	--	--	--	--
Totals (lb/hr)	367.85	31.84	81.70	2.50	24.25	23.75	19,435.03

B. Daily

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	698.52	60.32	331.08	0.62	54.68	54.68	66,066.69
Combustion - External	23.50	3.52	193.88	2.55	4.90	4.90	76,377.60
Combustion - Flare	2.23	3.95	12.14	49.29	0.66	0.66	3,840.22
Fugitive Components	--	225.16	--	--	--	--	--
Supply Boat	2,000.10	72.06	297.02	0.73	120.36	115.55	78,931.03
Emergency Response	--	--	--	--	--	--	--
Survival Capsules	41.48	1.26	5.79	0.02	2.44	2.34	1,649.13
Crew Boat	2,291.28	74.62	337.00	0.84	135.82	130.39	90,849.64
Pigging	--	6.13	--	--	--	--	--
Sumps/Tanks/Separators	--	1.38	--	--	--	--	--
Solvent Usage	--	10.96	--	--	--	--	--
Totals (lb/day)	5,057.11	459.37	1,176.91	54.05	318.85	308.51	317,714.31

C. Quarterly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	28.55	2.34	13.77	0.03	2.06	2.06	2,786.56
Combustion - External	1.07	0.16	8.85	0.12	0.22	0.22	3,484.73
Combustion - Flare	0.51	0.92	2.83	18.21	0.15	0.15	893.35
Fugitive Components	--	10.27	--	--	--	--	--
Supply Boat	14.71	0.79	3.21	0.01	1.30	1.24	846.32
Emergency Response	0.90	0.03	0.07	0.00	0.05	0.05	35.68
Survival Capsules	0.04	0.03	0.03	0.03	0.03	0.03	1.72
Crew Boat	12.52	3.22	13.17	0.03	0.90	0.86	841.00
Pigging	--	0.02	--	--	--	--	--
Sumps/Tanks/Separators	--	0.06	--	--	--	--	--
Solvent Usage	--	0.50	--	--	--	--	--
Totals (TPQ)	58.31	18.35	41.93	18.42	4.71	4.62	8,889.36

D. Annual

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	71.64	5.97	45.89	0.09	5.21	5.21	9,461.79
Combustion - External	4.29	0.64	35.38	0.46	0.89	0.89	13,938.91
Combustion - Flare	2.05	3.68	11.30	72.83	0.61	0.61	3,573.39
Fugitive Components	--	41.09	--	--	--	--	--
Supply Boat	58.85	3.16	12.85	0.03	5.18	4.98	3,385.29
Emergency Response	3.59	0.11	0.29	0.00	0.21	0.20	142.64
Survival Capsules	0.17	0.03	0.03	0.03	0.03	0.03	6.87
Crew Boat	50.07	3.22	13.17	0.03	3.58	3.45	3364.01
Pigging	--	0.09	--	--	--	--	--
Sumps/Tanks/Separators	--	0.25	--	--	--	--	--
Solvent Usage	--	2.00	--	--	--	--	--
Totals (TPY)	190.66	60.25	118.92	73.48	15.72	15.37	33,872.91

Table 5.6 Federal Potential to Emit

A. Hourly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	159.14	12.87	41.81	0.07	11.53	11.53	7,899.75
Combustion - External	0.98	0.15	8.08	0.30	0.20	0.20	4.90
Combustion - Flare	0.09	0.16	0.51	2.05	0.03	0.03	0.66
Fugitive Components	--	9.38	--	--	--	--	--
Supply Boat	100.32	4.04	15.53	0.04	6.13	5.89	112.20
Emergency Response	--	--	--	--	--	--	--
Survival Capsules	1.73	0.05	0.24	0.00	0.10	0.10	2.34
Crew Boat	105.59	3.44	15.53	0.04	6.26	6.01	4,186.62
Pigging	--	1.23	--	--	--	--	--
Sumps/Tanks/Separators	--	0.06	--	--	--	--	--
Solvent Usage	--	0.46	--	--	--	--	--
Totals (lb/hr)	367.85	31.84	81.70	2.50	24.25	23.75	12,206.47

B. Daily

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	698.52	60.32	331.08	0.62	54.68	54.68	66,066.69
Combustion - External	23.50	3.52	193.88	2.55	4.90	4.90	3,182.40
Combustion - Flare	2.23	3.95	12.14	49.29	0.66	0.66	160.01
Fugitive Components	--	225.16	--	--	--	--	--
Supply Boat	2,000.10	72.06	297.02	0.73	120.36	115.55	4,551.05
Emergency Response	--	--	--	--	--	--	--
Survival Capsules	41.48	1.26	5.79	0.02	2.44	2.34	68.71
Crew Boat	2,291.28	74.62	337.00	0.84	135.82	130.39	90,849.64
Pigging	--	6.13	--	--	--	--	--
Sumps/Tanks/Separators	--	1.38	--	--	--	--	--
Solvent Usage	--	10.96	--	--	--	--	--
Totals (lb/day)	5,057.11	459.37	1,176.91	54.05	318.85	308.51	164,878.50

C. Quarterly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	28.55	2.34	13.77	0.03	2.06	2.06	2,786.56
Combustion - External	1.07	0.16	8.85	0.12	0.22	0.22	0.89
Combustion - Flare	0.51	0.92	2.83	18.21	0.15	0.15	0.61
Fugitive Components	--	10.27	--	--	--	--	--
Supply Boat	14.71	0.79	3.21	0.01	1.30	1.24	4.98
Emergency Response	0.90	0.03	0.07	0.00	0.05	0.05	0.20
Survival Capsules	0.04	0.03	0.03	0.03	0.03	0.03	0.03
Crew Boat	12.52	3.22	13.17	0.03	0.90	0.86	841.00
Pigging	--	0.02	--	--	--	--	--
Sumps/Tanks/Separators	--	0.06	--	--	--	--	--
Solvent Usage	--	0.50	--	--	--	--	--
Totals (TPQ)	58.31	18.35	41.93	18.42	4.71	4.62	3,634.28

D. Annual

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion - Engines	71.64	5.97	45.89	0.09	5.21	5.21	9,461.79
Combustion - External	4.29	0.64	35.38	0.46	0.89	0.89	3,484.73
Combustion - Flare	2.05	3.68	11.30	72.83	0.61	0.61	893.35
Fugitive Components	--	41.09	--	--	--	--	--
Supply Boat	58.85	3.16	12.85	0.03	5.18	4.98	846.32
Emergency Response	3.59	0.11	0.29	0.00	0.21	0.20	35.68
Survival Capsules	0.17	0.03	0.03	0.03	0.03	0.03	1.72
Crew Boat	50.07	3.22	13.17	0.03	3.58	3.45	3,364.01
Pigging	--	0.09	--	--	--	--	--
Sumps/Tanks/Separators	--	0.25	--	--	--	--	--
Solvent Usage	--	2.00	--	--	--	--	--
Totals (TPY)	190.66	60.25	118.92	73.48	15.72	15.37	18,087.59

Table 5.7 Estimated Permit Exempt Emissions**A. Annual**

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Welder 70-304	0.11	0.01	0.02	0.01	0.01	0.01
Air Compressor 380 1906/ Tag #20-212	0.02	0.00	0.00	0.00	0.00	0.00
Welder RCD-12413 AC	0.08	0.01	0.02	0.01	0.01	0.01
Welder DC-9805003894	0.08	0.01	0.02	0.01	0.01	0.01
Welder LDC-8330AC	0.08	0.01	0.02	0.01	0.01	0.01
Helicopters	1.82	3.90	0.23	5.27	0.25	0.25
Surface Coating - Maintenance	0.00	4.00	0.00	0.00	0.00	0.00
Abrasive Blasting	0.00	0.00	0.00	0.00	0.00	0.00
Total (TPY):	2.19	7.93	0.31	5.31	0.28	0.28

Table 5.8 Facility Net Emissions Increase (FNEI-90)

I. This Projects "I" NEI-90													
Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
II. This Facility's "P1s"													
Enter all facility "P1" NEI-90s below:													
Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
PTO 9101	1/11/2000			6.92	0.85								
ATC/PTO 10183	4/23/2001	449.520		0.140		71.160	0.290	22.520		26.600		25.530	
ATC/PTO 10736	11/9/2001			6.700									
ATC/PTO 10992	4/1/2003			2.551	0.466								
ATC/PTO 11236	9/24/2004	1.061	0.000	0.100	0.000	0.262	0.000	0.081	0.000	0.086	0.000	0.083	0.000
ATC 11132-02	3/4/2005			16.106	2.939								
ATC/PTO 13041	6/12/2009			3.175	0.579								
ATC/PTO 13491	10/6/2011			7.945	1.450								
Totals		450.58	0.00	43.64	6.28	71.42	0.29	22.60	0.00	26.69	0.00	25.61	0.00
Notes: (1) Facility NEI from IDS.													
III. This Facility's "P2" NEI-90 Decreases													
Enter all facility "P2" NEI-90s below:													
Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Totals		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Notes: (1) Facility NEI from IDS.													
IV. This Facility's Pre-90 "D" Decreases													
Enter all facility "D" decreases below:													
Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Totals		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Notes: (1) Facility "D" from IDS.													
V. Calculated This Facility's NEI-90													
Table below summarizes facility NEI-90 as equal to: I+ (P1-P2) -D													
Term	NOx		ROC		CO		SOx		PM		PM10		
	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	
Project "I"	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
P1	450.58	0.00	43.64	6.28	71.42	0.29	22.60	0.00	26.69	0.00	25.61	0.00	
P2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
D	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FNEI-90	450.58	0.00	43.64	6.28	71.42	0.29	22.60	0.00	26.69	0.00	25.61	0.00	
Notes: (1) Resultant FNEI-90 from above Section I thru IV data. (2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding. (3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.													

6.0 Air Quality Impact Analyses

6.1 Modeling

Air quality modeling was not required for the issuance of this OCS operating permit. Modeling was performed for ExxonMobil's onshore portion of the SYU Expansion Project in 1987. The air impacts from the operation of Platform Heritage were addressed in ATC 5651 (11/87) and the results are summarized in Part 70/District PTO 5651.

6.2 Increments

An increment analysis was not required for the issuance of this OCS operating permit. An increment analysis was performed for ExxonMobil's onshore portion of the SYU Expansion Project in 1987. The air impacts from the operation of Platform Heritage were addressed in ATC 5651 (11/87) and the results are summarized in Part 70/District PTO 5651.

6.3 Monitoring

Air quality monitoring was not required for the issuance of this OCS operating permit.

6.4 Health Risk Assessment

A Health Risk Assessment was not required for Platform Heritage.

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General

The stationary source is located in an ozone nonattainment area. Santa Barbara County has not attained the state ozone ambient air quality standards. The County also does not meet the state PM10 ambient air quality standards. Therefore, emissions from all emission units at the stationary source and its constituent facilities must be consistent with the provisions of the USEPA and State approved Clean Air Plans (CAP) and must not interfere with progress toward attainment of federal and state ambient air quality standards. Under District regulations, any modifications at the source that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Increases above offset thresholds will trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 55 lbs/day for all non-attainment pollutants except PM10, for which the level is 80 lbs/day.

7.2 Clean Air Plan

The 2007 Clean Air Plan, adopted by the District Board on August 16, 2007, addressed both federal and state requirements, serving as the maintenance plan for the federal eight-hour ozone standard and as the state triennial update required by the Health and Safety Code to demonstrate how the District will expedite attainment of the state eight-hour ozone standard. The plan was developed for Santa Barbara County as required by both the 1998 California Clean Air Act and the 1990 Federal Clean Air Act Amendments.

On January 20, 2011 the District Board adopted the 2010 Clean Air Plan. The 2010 Plan provides a three-year update to the 2007 Clean Air Plan. As Santa Barbara County has yet to attain the state eight-hour ozone standard, the 2010 Clean Air Plan demonstrates how the District plans to attain that standard. The 2010 Clean Air Plan therefore satisfies all state triennial planning requirements.

7.3. Offset Requirements

The *ExxonMobil - SYU Project* stationary source requires emission offsets. Offsets are required for all permitted emissions at the onshore LFC processing plant and for all NEI increases that occurred on the OCS Platforms since being subject to the requirements of the OCS Air Regulation (40 CFR Part 55). The specific offset requirements for Platform Heritage are detailed in Table 7-1 for ROC and Table 7-2 for SO_x.

7.4. Emission Reduction Credits

ATC 11132 Mod-02: ExxonMobil generated 0.459 TPY (0.115 TPQ) of ROC ERCs in order to offset emission increases from the IP/LP and HP gas expansion projects on Platform Heritage. These ERCs were created by implementation of an enhanced fugitive hydrocarbon inspection and maintenance program. The requirements for the emission reduction credits (enhanced I &M) authorized under DOI No. 0039 are identified in this permit.

DOI 042-01: ExxonMobil generated 1.843 tpq NO_x and 0.072 tpq PM/PM₁₀ due to the replacement of the diesel main propulsion and auxiliary engines on the dedicated crew boat for the Exxon – SYU project, the *M/V Broadbill*. This “repowering” of the vessel involved the installation of two new Tier II Detroit Diesel Series 60 propulsion engines (each rated at 600 bhp), and two new Tier II Northern Lights Model M40C2 auxiliary engines (each rated at 60 bhp).

Table 7.1 ROC Emission Offset Requirements

Reactive Organic Compounds (ROC)

NEI EMISSIONS FROM PROJECT	Reactive Organic Compounds (ROC)	
	TPQ	TPY
Compressor Skid Unit (PTO 9634)	0.15	0.59
Pig Receiver (ATC 9828)	0.01	0.02
Fugitive I&M Components (ATC 9828)	0.06	0.24
De Minimis Transfer	0.3643	1.4574
Gas Expansion Project HP (ATC 11132 Mod-02)	0.735	2.939
De Minimis Transfer	0.145	0.580
De Minimis Transfer (ATC/PTO 13491)	0.362	1.450
Total NEI:	1.82	7.28

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions		Distance Factor ^(a)	Offset Credit	
	TPQ	TPY		TPQ	TPY
1 Enhanced I&M at Exxon LFC (PTO 5651)	0.223	0.890	1.5	0.15	0.59
2 ERC # 0004-0103 ^(b)	0.080	0.310	1.2	0.07	0.26
3 ERC # 0079-0206 ^(c)	0.278	1.112	1.5	0.1853	0.7413
4 ERC # 0080-0307 ^(d)	0.331	1.324	1.5	0.2207	0.8827
5 ERC # 0081-0308 ^(e)	0.657	2.628	1.5	0.4380	1.7520
6 ERC # 0083-1103 ^(f)	0.640	2.560	6	0.1067	0.4267
7 ERC # 0029-0331 ^(g)	0.040	0.160	1.5	0.03	0.11
8 ERC # 0102-1108 ^(h)	0.050	0.200	6	0.01	0.03
9 ERC # 0114-1009 ⁽ⁱ⁾	0.263	1.052	1.2	0.219	0.876
10 ERC # 0115-1009 ⁽ⁱ⁾	0.488	1.953	1.2	0.407	1.628
11 ERC 125-0310 ^(j)	0.115	0.459	1.2	0.096	0.382
12 ERC 126-310 ^(j)	0.016	0.064	1.2	0.013	0.053
13 ERC # 0188-0811 ^(k)	0.174	0.696	1.2	0.145	0.580
14 ERC #0235-0811 ^(l)	0.434	1.730	1.2	0.362	1.450
Total Offsets:	3.79	15.14		2.44	9.76

Notes:

- ^(a) Ratios set according to District Guidelines and based on source distance from the SYU project. The discounted offset values shown are the undiscounted offset values divided by the discount ratio.
- ^(b) ERCs from ERC Certificate No. 0004-0103 (issued January 1988). ERC face value was 0.18 tpq ROC (of which 0.08 tpq was used for ATC 9828).
- ^(c) ERC Certificate #0079 is for ERCs generated due the shutdown of McGhan Medical Corporation's Carpinteria facility.
- ^(d) ERC Certificate #0080 is for ERCs generated due the shutdown of McGhan Medical Corporation's Goleta facility at 600 Pine Avenue.
- ^(e) ERC Certificate #0081 is for ERCs generated due the shutdown of BioEnterics Corporation facility at 1035 Cindy Lane in Carpinteria.
- ^(f) ERC Certificate #0083 is for ERCs generated due the shutdown of Grefco's Lompoc diatomaceous earth processing plant.
- ^(g) ERC Certificate #0029 is for ERCs generated due the shutdown of Santa Barbara Aerospace's jet aircraft refurbishment facility located at the Santa Barbara Municipal Airport.
- ^(h) ERC Certificate #0102 is for ERCs generated due the shutdown of Grefco's Lompoc diatomaceous earth processing plant.
- ⁽ⁱ⁾ These ERCs were generated per DOI #0034 due to a reduction in the fugitive I&M leak threshold on fugitive components permitted at POPCO Gas Plant per ATC/PTO 11130 and at Las Flores Canyon Oil and Gas Plant per ATC/PTO 11170.
- ^(j) ERCs generated per DOI #0039 and #0040 are due to a reduction in the fugitive I&M leak threshold on fugitive components permitted at Platform Heritage per ATC 11132 Mod -02 and at Las Flores Canyon Oil and Gas Plant per ATC/PTO 11410.
- ^(k) ERC Certificate #0188 is for ERCs generated due the installation of low NOx engines on the M/V Broadbill.
- Inter-pollutant trade - NOx for ROC.
- ^(l) ERC Certificate #0235-0811 is for ERCs generated due to the repowering of the M/V Broadbill.

Table 7.2 SO_x Emission Offset Requirements

Oxides of Sulfur (SO_x) ^(a)

Rule 359 ERC Liability for Platform Heritage	Oxides of Sulfur	
	TPQ	TPY
Planned Flaring (Table 5.1-4)	4.95	19.78
Total NEI:	4.95	19.78

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions		Distance Factor ^(b)	Offset Credit	
	TPQ	TPY		TPQ	TPY
1. Removal of OS&T Vessel ^(c)	5.17	20.68	1.0	5.17	20.68
Total Offsets:	5.17	20.68		5.17	20.68

Notes:

^(a) SO_x as SO₂

^(b) Ratios set according to District Guidelines and based on source distance from the SYU project. The discounted offset values shown are the undiscounted offset values divided by the discount ratio.

^(c) ERCs from shutdown of OS&T per PTO 9102-01 (1/25/95). Distance factor of 1.0:1 as the ERCs are required per Rule 359.

8.0 Lead Agency Permit Consistency

A Final Development Plan for the Santa Ynez Unit/ Las Flores Canyon project was approved by the Santa Barbara Planning Commission on September 15, 1987. This Plan included permit conditions XII-3, 5, 8, 11 and 17 which required ExxonMobil to fully mitigate adverse air quality impacts of the project which would affect the county. In part, these conditions required the following measures: full mitigation of all NO_x and ROC construction and operation emissions associated with the SYU project (including OCS emission sources); installation of Ambient Air Monitoring and Continuous Emission Monitoring Stations, and submittal of an air quality related Emergency Episode Plan. These requirements are included as part of ATC 5651 issued on November 19, 1987 and all subsequent permits that supersede that permit.

The United States Department of Interior's Mineral Management Service approved the *Development and Production Plan* for Platform Heritage on September 20, 1985.

8.1. Lead Agency/CEQA

The District is the lead agency for this project. Pursuant to Section 15061(b)(3) of the California Environmental Quality Act ("CEQA") Guidelines, the proposed modifications authorized under this permit are exempt from CEQA because the project does not have the potential for causing a significant effect on the environment. Further, no cross-media impacts are projected.

9.0 Permit Conditions

This section lists the applicable permit conditions for Platform Heritage. Section A lists the standard administrative conditions. Section B lists 'generic' permit conditions, including emission standards, for all equipment in this permit. Section C lists conditions affecting specific equipment. Section D lists non-federally enforceable (i.e., District only) permit conditions. Conditions listed in Sections A, B and C are enforceable by the USEPA, the District, the State of California and the public. Conditions listed in Section D are enforceable only by the District and the State of California. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable.

9.A Standard Administrative Conditions

The following federally enforceable administrative permit conditions apply to Platform Heritage. In the case of a discrepancy between the wording of a condition and the applicable District rule, the wording of the rule shall control.

- A.1 **Condition Acceptance.** Acceptance of this operating permit by ExxonMobil shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: PTO 9102*]
- A.2 **Grounds for Revocation.** Failure to abide by and faithfully comply with this permit or any Rule, Order, or Regulation may constitute grounds for revocation pursuant to California Health & Safety Code Section 42307 *et seq.* [*Re: PTO 9102*]
- A.3 **Defense of Permit.** ExxonMobil agrees, as a condition of the issuance and use of this PTO, to defend at its sole expense any action brought against the District because of issuance of this permit. ExxonMobil shall reimburse the District for any and all costs including, but not limited

to, court costs and attorney's fees which the District may be required by a court to pay as a result of such action. The District may, at its sole discretion, participate in the defense of any such action, but such participation shall not relieve ExxonMobil of its obligation under this condition. The District shall bear its own expenses for its participation in the action. [Re: PTO 9102]

- A.4 **Reimbursement of Costs.** All reasonable expenses, as defined in District Rule 210, incurred by the District, District contractors, and legal counsel for all activities that follow the issuance of this PTO permit, including but not limited to permit condition implementation, implementation of Regulation XIII (*Part 70 Operating Permits*), compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by ExxonMobil as required by Rule 210. [Re: PTO 9102, District Rule 210]
- A.5 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the District or its agents, ExxonMobil shall make such records available or provide access to such facilities upon notice from the District. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. [Re: PTO 9102]
- A.6 **Compliance.** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rule, regulation, ambient air quality standard or air quality increment. [Re: PTO 9102]
- A.7 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application and supplements thereof (as documented in the District's project file) and the District's analyses under which this permit is issued as documented in the Permit Analyses prepared for and issued with the permit. [Re: PTO 9102]
- A.8 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on the Santa Ynez Unit Project by:
- a. The County of Santa Barbara in Final Development Plan Permit 87-DP-32cz and any subsequent modifications;
 - b. The Santa Barbara County Air Pollution Control District in Authority to Construct 5651, Permit to Operate 5651, and any subsequent modifications to either permit; and
 - c. The California Coastal Commission in the consistency determination for the Project with the California Coastal Act. [Re: PTO 9102]
- A.9 **Compliance with Department of Interior Permits.** ExxonMobil shall comply with all air quality control requirements imposed by the Department of the Interior in the Development and Production Plan approved for Platform Heritage on September 20, 1985 and any subsequent modifications. Such requirements shall be enforceable by the District. [Re: PTO 9102]
- A.10 **Compliance with Permit Conditions.**
- a. The permittee shall comply with all permit conditions in Sections 9.A, 9.B and 9.C.

- b. This permit does not convey property rights or exclusive privilege of any sort.
- c. Any permit noncompliance with sections 9.A, 9.B, or 9.C constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and re-issuance, or modification; or for denial of a permit renewal application.
- d. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
- e. A pending permit action or notification of anticipated noncompliance does not stay any permit condition.
- f. Within a reasonable time period, the permittee shall furnish any information requested by the Control Officer, in writing, for the purpose of determining:
 - (1) Compliance with the permit, or
 - (2) Whether or not cause exists to modify, revoke and reissue, or terminate a permit or for an enforcement action.
- a. In the event that any condition herein is determined to be in conflict with any other condition contained herein, then, if principles of law do not provide to the contrary, the condition most protective of air quality and public health and safety shall prevail to the extent feasible. [*Re: 40 CFR Part 70.6.(a)(6), District Rules 1303.D.1*]

A.11 **Emergency Provisions.** The permittee shall comply with the requirements of the District, Rule 505 (Upset/Breakdown rule) and/or District Rule 1303.F, whichever is applicable to the emergency situation. In order to maintain an affirmative defense under Rule 1303.F, the permittee shall provide the District, in writing, a “notice of emergency” within 2 working days of the emergency. The “notice of emergency” shall contain the information/documentation listed in Sections (1) through (5) of Rule 1303.F. [*Re: 40 CFR 70.6(g), District Rule 1303.F*]

A.12 **Compliance Plans.**

- a. The permittee shall comply with all federally enforceable requirements that become applicable during the permit term in a timely manner.
- a. For all applicable equipment, the permittee shall implement and comply with any specific compliance plan required under any federally-enforceable rules or standards. [*Re: District Rule 1302.D.2*]

A.13 **Right of Entry.** The Regional Administrator of USEPA, the Control Officer, or their authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises where a Part 70 Source is located or where records must be kept:

- a. To inspect the stationary source, including monitoring and control equipment, work practices, operations, and emission-related activity;
- b. To inspect and duplicate, at reasonable times, records required by this Permit to Operate;

- c. To sample substances or monitor emissions from the source or assess other parameters to assure compliance with the permit or applicable requirements, at reasonable times. Monitoring of emissions can include source testing. [*Re: District Rule 1303.D.2*]
- A.14 **Indemnity and Separation Clauses.** The Applicant shall defend, indemnify and hold harmless the District or its agents, officers and employees from any claim, action or proceeding against the District or its agents, officers or employees, to attack, set aside, void, or annul, in whole or in part, the approval granted herein. In the event that the District fails promptly to notify the Applicant of any such claim, action or proceeding, or that the District fails to cooperate fully in the defense of said claim, this condition shall thereafter be of no force or effect. In the event that any condition contained herein is determined to be invalid, then all remaining conditions shall remain in force. [*Re: District Rules 103 and 1303.D.1*]
- A.15 **Permit Life.** The Part 70 permit shall become invalid three years from the date of issuance unless a timely and complete renewal application is submitted to the District. Any operation of the source to which this Part 70 permit is issued beyond the expiration date of this Part 70 permit and without a valid Part 70 operating permit (or a complete Part 70 permit renewal application) shall be a violation of the CAAA, § 502(a) and 503(d) and of the District rules.
- a. The permittee shall apply for renewal of the Part 70 permit no later than 6 months before the date of the permit expiration. Upon submittal of a timely and complete renewal application, the Part 70 permit shall remain in effect until the Control Officer issues or denies the renewal application. [*Re: District Rule 1304.D.1*]
- A.16 **Payment of Fees.** The permittee shall reimburse the District for all its Part 70 permit processing and compliance expenses for the stationary source on a timely basis. Failure to reimburse on a timely basis shall be a violation of this permit and of applicable requirements and can result in forfeiture of the Part 70 permit. Operation without a Part 70 permit subjects the source to potential enforcement action by the District and the USEPA pursuant to section 502(a) of the Clean Air Act. [*Re: District Rules 1303.D.1 and 1304.D.11, 40 CFR 70.6(a)(7)*]
- A.17 **Prompt Reporting of Deviations.** The permittee shall submit a written report to the District documenting each and every deviation from the requirements of this permit or any applicable federal requirements within 7 days after discovery of the violation, but not later than 6 months after the date of occurrence. The report shall clearly document:
- a. The probable cause and extent of the deviation,
- b. Equipment involved,
- c. The quantity of excess pollutant emissions, if any, and
- d. Actions taken to correct the deviation.
- The requirements of this condition shall not apply to deviations reported to District in accordance with Rule 505. Breakdown Conditions, or Rule 1303.F Emergency Provisions. [*District Rule 1303.D.1, 40 CFR 70.6(a)(3)*]
- A.18 **Reporting Requirements/Compliance Certification.** The permittee shall submit compliance certification reports to the USEPA and the Control Officer every six months. These reports shall be submitted on District approved forms and shall identify each applicable requirement/condition

of the permit, the compliance status with each requirement/condition, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations from permit requirement. The reporting periods shall be each half of the calendar year, e.g., January through June for the first half of the year. These reports shall be submitted by September 1st and March 1st, respectively, each year. Supporting monitoring data shall be submitted in accordance with the “Semi-Annual Compliance Verification Report” condition in section 9.C. The permittee shall include a written statement from the responsible official, which certifies the truth, accuracy, and completeness of the reports. [*Re: District Rules 1303.D.1, 1302.D.3, 1303.2.c*]

- A.19 **Federally Enforceable Conditions.** Each federally enforceable condition in this permit shall be enforceable by the USEPA and members of the public. None of the conditions in the District-only enforceable section of this permit are federally enforceable or subject to the public/USEPA review [*Re: CAAA, § 502(b)(6), 40 CFR 70.6(b)*]
- A.20 **Recordkeeping Requirements.** The permittee shall maintain records of required monitoring information that include the following:
- a. The date, place as defined in the permit, and time of sampling or measurements;
 - b. The date(s) analyses were performed;
 - c. The company or entity that performed the analyses;
 - d. The analytical techniques or methods used;
 - e. The results of such analyses; and
 - f. The operating conditions as existing at the time of sampling or measurement;
 - g. The records (electronic or hard copy), as well as all supporting information including calibration and maintenance records, shall be maintained for a minimum of five (5) years from date of initial entry by the permittee and shall be made available to the District upon request. [*Re: District Rule 1303.D.1.f, 40 CFR 70.6(a)(3)*]
- A.21 **Conditions for Permit Reopening.** The permit shall be reopened and revised for cause under any of the following circumstances:
- a. Additional Requirements: If additional applicable requirements (e.g., NSPS or MACT) become applicable to the source which has an unexpired permit term of three (3) or more years, the permit shall be reopened. Such a reopening shall be completed no later than 18 months after promulgation of the applicable requirement. However, no such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended. All such re-openings shall be initiated only after a 30 day notice of intent to reopen the permit has been provided to the permittee, except that a shorter notice may be given in case of an emergency.
 - b. Inaccurate Permit Provisions: If the District or the USEPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

- c. Applicable Requirement: If the District or the USEPA determines that the permit must be revised or revoked to assure compliance with any applicable requirement including a federally enforceable requirement, the permit shall be reopened. Such re-openings shall be made as soon as practicable.
- d. Administrative procedures to reopen a permit shall follow the same procedures as apply to initial permit issuance. Re-openings shall affect only those parts of the permit for which cause to reopen exists.
- e. If a permit is reopened, the expiration date does not change. Thus, if the permit is reopened, and revised, then it will be reissued with the expiration date applicable to the re-opened permit. [Re: 40 CFR 70.7(f), 40 CFR 70.6(a)]

A.22 **Credible Evidence.** Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defenses otherwise available to the permittee, including but not limited to, any challenge to the Credible Evidence Rule (see 62 Fed. Reg. 8314, Feb. 24, 1997), in the context of any future proceeding. [Re: 40 CFR 52.12(c)]

9.B. Generic Conditions

The generic conditions listed below apply to all emission units, regardless of their category or emission rates. These conditions are federally enforceable. These rules apply to the equipment and operations at Platform Heritage as they currently exist. Compliance with these requirements is discussed in Section 3.4.2. In the case of a discrepancy between the wording of a condition and the applicable District rule, the wording of the rule shall control.

B.1 **Circumvention (Rule 301).** A person shall not build, erect, install, or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of Division 26 (Air Resources) of the Health and Safety Code of the State of California or of these Rules and Regulations. This Rule shall not apply to cases in which the only violation involved is of Section 41700 of the Health and Safety Code of the State of California, or of District Rule 303. [Re: District Rule 301]

B.2 **Visible Emissions (Rule 302).** ExxonMobil shall not discharge into the atmosphere from any single source of emission any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

- a. As dark or darker in shade as that designated as No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines, or
- b. Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subsection B.2(a) above.

For those sources listed in Condition 9.C.25 (*Visible Emissions*), ExxonMobil shall be in compliance with the requirements of this Rule in accordance with the monitoring and compliance recordkeeping procedures in Condition 9.C.25 (*Visible Emissions*). [Re: District Rule 302]

- B.3 **PM Concentration - South Zone (Rule 305).** ExxonMobil shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in Table 305(a) of Rule 305. [*Re: District Rule 305*]
- B.4 **Specific Contaminants (Rule 309).** ExxonMobil shall not discharge into the atmosphere from any single source sulfur compounds, carbon monoxide and combustion contaminants in excess of the applicable standards listed in Sections A, E and G of Rule 309. [*Re: District Rule 309*].
- B.5 **Odorous Organic Sulfides (Rule 310).** ExxonMobil shall not discharge into atmosphere H₂S and organic sulfides that result in a ground level impact beyond the ExxonMobil property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. [*Re: District Rule 310*]
- B.6 **Sulfur Content of Fuels (Rule 311).** ExxonMobil shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 239 ppmvd or 15 gr/100 scf (calculated as H₂S) for gaseous fuel. Compliance with this condition shall be based on daily measurements of the fuel gas using (Draeger tubes, ASTM, or other District-approved) methods and diesel fuel billing records or other data showing the certified sulfur content for each shipment. [*Re: District Rule 311*]
- B.7 **Organic Solvents (Rule 317).** ExxonMobil shall comply with the emission standards listed in Rule 317.B. Compliance with this condition shall be based on ExxonMobil's compliance with Condition C.8 (*Solvent Usage*) of this permit. [*Re: District Rule 317*]
- B.8 **Vacuum Producing Devices or Systems – Southern Zone (Rule 318).** ExxonMobil shall not discharge into the atmosphere more than 3 pounds of organic materials in any one hour from any vacuum producing devices or systems, including hot wells and accumulators, unless said discharge has been reduced by at least 90 percent. [*Re: District Rule 318*]
- B.9 **Solvent Cleaning Operations (Rule 321).** ExxonMobil shall comply with the requirements listed in Sections D, G, I, P and Q of Rule 321. Compliance with this condition shall be based on ExxonMobil's compliance with Condition C.8 (*Solvent Usage*) of this permit as well as District inspections. [*Re: District Rule 321*]
- B.10 **Metal Surface Coating Thinner and Reducer (Rule 322).** The use of photochemically reactive solvents as thinners or reducers in metal surface coatings is prohibited. Compliance with this condition shall be based on ExxonMobil's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: District Rule 322*]
- B.11 **Architectural Coatings (Rule 323).** ExxonMobil shall comply shall comply with the coating ROC content and handling standards listed in Rule 323.D as well as the Administrative requirements listed in Rule 323.F. Compliance with this condition shall be based on ExxonMobil's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: District Rule 323*]
- B.12 **Disposal and Evaporation of Solvents (Rule 324).** ExxonMobil shall not dispose through atmospheric evaporation of more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on ExxonMobil's compliance

with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [Re: *District Rule 324*]

- B.13 **Continuous Emissions Monitoring (Rule 328).** ExxonMobil shall comply with the requirements of Section C, F, G, H and I of Rule 328 for the fuel gas hydrogen sulfide analyzer. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit as well as on-site inspections. [Re: *District Rule 328*]
- B.14 **Adhesives and Sealants (Rule 353).** The permittee shall not use adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers, unless the permittee complies with the following:
- a. Such materials used are purchased or supplied by the manufacturer or suppliers in containers of 16 fluid ounces or less; or alternately
 - b. When the permittee uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353.B.1, the total reactive organic compound emissions from the use of such material shall not exceed 200 pounds per year unless the substances used and the operational methods comply with Sections D, E, F, G, and H of Rule 353. Compliance shall be demonstrated by recordkeeping in accordance with Section B.2 and/or Section O of Rule 353. [Re: *District Rule 353*]
- B.15 **Oil and Natural Gas Production MACT.** ExxonMobil submitted HAP calculations that show each of these facilities qualifies an area source (not a major source), and thus are not subject to the MACT. This is based on the definitions of “facility” and “major source” in the MACT. The data shows that each platform has less than 10 TPY combined HAPs. [Re: 40 CFR 63, Subpart HH]

9.C Requirements and Equipment Specific Conditions

Federally-enforceable conditions, including emissions and operations limits, monitoring, recordkeeping and reporting are included in this section for each specific group of equipment as well as other non-generic requirements.

- C.1 **Internal Combustion Engines.** The following equipment are included in this emissions unit category:

Device Name	ExxonMobil ID	APCD Device No
<i>Stationary Internal Combustion Engines (Table A)</i>		
Pedestal Crane East	ZZZ-507	5350
Emergency Production Generator	ZAN-515	5371
Firewater Pump	PBE-357	5372
Firewater Pump	PBE-367	7143
Emergency Drilling Engine	ZAN-515	5370
B - Side Cement Pumping Skid		112508
C - Side Cement Pumping Skid		112507
Cuttings Reinjection Pump		112509

- a. Emission Limits: Mass emissions from the devices listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit. In addition, the following specific emission limits apply:
- i. *Prime Engines* - Emissions from the crane engine, B-side cement pumping skid engine, C-side cement pumping skid engine, and the cuttings reinjection pump engine shall not exceed any of the following: NO_x – 700 ppmv at 15% O₂, ROC – 750 ppmv at 15% O₂, CO – 4,500 ppmv at 15% O₂. Compliance shall be based on quarterly or more frequent portable analyzer inspections in accordance with Rule 333.F and source testing as applicable per Rule 333.I.8.
- b. Operational Limits: The equipment permitted herein is subject to the following operational restrictions listed below. Emergency use operations, as defined in the ATCM⁵, have no operational hours limitations.
- i. *Fuel Use Limits* - ExxonMobil shall comply with the following fuel limits:
- (1) The East Pedestal Crane engine shall not use more than: 537 gallons per day; 24,491 gallons per quarter; 97,962 gallons per year of diesel fuel.
 - (2) The B- Side Cement Pump shall not use more than 690 gallons per day; 62,990 gallons per quarter; 251,961 gallons per year of diesel fuel.
 - (3) The C- Side Cement Pump shall not use more than 690 gallons per day; 62,990 gallons per quarter; 251,961 gallons per year of diesel fuel.
 - (4) The Cuttings Reinjection Pump shall not use more than 621 gallons per day; 56,691 gallons per quarter; 226,265 gallons per year of diesel fuel.
- ii. *Engine Identification and Maintenance* - Each IC engine shall be identified with a permanently-affixed plate, tag or marking, referencing either: (i) the IC engine's

⁵ As used in the permit, "ATCM" means Section 93115, Title 17, California Code of Regulations. Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines

make, model, serial number, rated BHP and corresponding RPM; or (ii) the operator's unique tag number. The tag shall be made accessible and legible to facilitate District inspection of the IC engine.

- iii. *High Pressure Fuel Injectors* - If high pressure fuel injectors are used to comply with Rule 333 standards, then that injector type shall be used on the engine for the life of the engine except as noted below. ExxonMobil may revert to the normal pressure fuel injectors if District-approved source testing shows that the Rule 333 standards are achieved.
- iv. *Maintenance & Testing Use Limit* - The stationary emergency standby diesel-fueled CI engines subject to this permit (firewater pumps and emergency generator engines), shall limit maintenance and testing operations to no more than 200 hours per year.
- v. *Fuel and Fuel Additive Requirements* - The permittee may only add CARB Diesel, or an alternative diesel fuel that meets the requirements of the ATCM Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the ATCM Verification Procedure, or any combination of the above to each engine or any fuel tank directly attached to each engine.
- vi. *Diesel IC Engines - Particulate Matter Emissions* - To ensure compliance with District Rules 205.A, 302, 304, 309 and the California Health and Safety Code Section 41701, ExxonMobil shall implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. ExxonMobil shall implement the District approved *Diesel Engine Particulate Matter (PM) Operation and Maintenance Plan* for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules that ExxonMobil will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized. All project diesel-fired engines, regardless of exemption status, shall be included in this Plan.
- vii. *Temporary Engine Replacements - DICE ATCM*. Any reciprocating internal combustion engine subject to this permit and the stationary diesel ATCM may be replaced temporarily only if the requirements (1 – 7) listed herein are satisfied.
 - 1. The permitted engine is in need of routine repair or maintenance.
 - 2. The permitted engine that is undergoing routine repair or maintenance is returned to its original service within 180 days of installation of the temporary engine.
 - 3. The temporary replacement engine has the same or lower manufacturer rated horsepower and same or lower potential to emit of each pollutant as the permitted engine that is being temporarily replaced. At the written request of the permittee, the District may approve a replacement engine with a larger rated horsepower than the permitted engine if the proposed temporary engine

has manufacturer guaranteed emissions (for a brand new engine) or source test data (for a previously used engine) less than or equal to the permitted engine.

4. The temporary replacement engine shall comply with all rules and permit requirements that apply to the permitted engine that is undergoing routine repair or maintenance.
 5. For each permitted engine to be temporarily replaced, the permittee shall submit a completed *Temporary IC Engine Replacement Notification* form (Form ENF-94) within 14 days of the temporary engine being installed. This form shall be sent electronically to: engr@sbcapcd.org.
 6. Within 14 days upon return of the original permitted engine to service, the permittee shall submit a completed *Temporary IC Engine Replacement Report* form (Form ENF-95). This form shall be sent electronically to: engr@sbcapcd.org.
 7. Any engine in temporary replacement service shall be immediately shut down if the District determines that the requirements of this condition have not been met. This condition does not apply to engines that have experienced a cracked block (unless under manufacturer's warranty), to engines for which replacement parts are no longer available, or new engine replacements {including "reconstructed" engines as defined in the ATCM}. Such engines are subject to the provisions of New Source Review and the new engine requirements of the ATCM.
- (vii) *Permanent Engine Replacements.* Any E/S engine, firewater pump engine or engine used for an essential public service that breaks down and cannot be repaired may install a new replacement engine without first obtaining an ATC permit only if the requirements (1 – 6) listed herein are satisfied.
- (1) The permitted stationary diesel IC engine is an E/S engine, a firewater pump engine or an engine used for an essential public service (as defined by the District).
 - (2) The engine breaks down, cannot be repaired and needs to be replaced by a new engine.
 - (3) The facility provides "good cause" (in writing) for the immediate need to install a permanent replacement engine prior to the time period before an ATC permit can be obtained for a new engine. The new engine must comply with the requirements of the ATCM for new engines. If a new engine is not immediately available, a temporary engine may be used while the new replacement engine is being procured. During this time period, the temporary replacement engine must meet the same guidelines and procedures as defined in the permit condition above (*Temporary Engine Replacements - DICE ATCM*).

- (4) An Authority to Construct application for the new permanent engine is submitted to the District within 15 days of the existing engine being replaced and the District permit for the new engine is obtained no later than 180 days from the date of engine replacement (these timelines include the use of a temporary engine).
 - (5) For each permitted engine to be permanently replaced pursuant to the condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of either the permanent or temporary engine being installed. This form shall be sent electronically to: *engr@sbcapcd.org*.
 - (6) Any engine installed (either temporally or permanently) pursuant to this permit condition shall be immediately shut down if the District determines that the requirements of this condition have not been met.
 - (ix) *Notification of Non-Compliance.* Owners or operators who have determined that they are operating their stationary diesel-fueled engine(s) in violation of the requirements specified in the ATCM shall notify the District immediately upon detection of the violation and shall be subject to District enforcement action.
 - (x) *Notification of Loss of Exemption.* Owners or operators of in-use stationary diesel-fueled CI engines, who are subject to an exemption specified in the ATCM from all or part of the requirements of the ATCM, shall notify the District immediately after they become aware that the exemption no longer applies and shall demonstrate compliance within 180 days after notifying the District.
- c. Monitoring: The following source testing and periodic monitoring conditions apply to the crane, cement pumping skid and cuttings reinjection pump engines:
- (i) *Fuel Meters* - The amount of fuel combusted in each engine shall be measured using permanently installed District-approved fuel meters dedicated to each engine. As an alternative to in-line fuel meters, ExxonMobil may report individual engine hours of operation utilizing a District-approved elapsed time meter⁶. A monthly log shall be maintained that records the fuel usage (or hours of operation) of each engine.
 - (ii) *Inspection and Maintenance Plan (I&M Plan)* - ExxonMobil shall implement inspections on each engine according to the District-approved *Engine Inspection and Maintenance Plan* consistent with the requirements of Rule 333.F. This Plan, and any subsequent District-approved revisions, is incorporated by reference as an enforceable part of this permit.

⁶ The hours of operation, along with the engine horsepower rating and BSFC data as listed in Table 5.1-1 of this permit, a fuel correction factor of 1.06, and a high heating value of 138,200 Btu/gal will be used to determine the number of gallons of fuel consumed per time period.

- (iii) *Source Testing* - For each engine, ExxonMobil shall perform source testing of air emissions and process parameters consistent with the requirement of Condition C.12 (*Source Testing*) and in accordance with the requirements of Rule 333.i.
 - (iv) *Fuel Data* - ExxonMobil shall maintain documentation of the sulfur content (as determined by District-approved ASTM methods) of each diesel fuel shipment as certified in the fuel suppliers billing vouchers.
 - (v) *Non-Resettable Hour Meter* - Each stationary engine subject to this permit shall have installed a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District has determined (in writing) that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.
- d. Recordkeeping: ExxonMobil shall keep the required logs, as applicable to this permit, which demonstrate compliance with emission limits, operation limits and monitoring requirements above. All logs shall be available to the District upon request. District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*) can be used for this requirement. Written information (logs) shall include:
- (i) Daily, quarterly and annual fuel usage in units of gallons for the East Pedestal Crane and cement pumping skid and cuttings reinjection pump engines.
 - (ii) The hours of operation for the firewater pump, drill rig emergency power generator and the production emergency power generator (by ID number). The log shall detail the number of operating hours on each day the engine is operated and the total monthly and cumulative annual hours. The log shall specify the following:
 - (1) emergency use hours of operation;
 - (2) maintenance and testing hours of operation;
 - (3) hours of operation for all uses other than those specified in items (1) and (2) above along with a description of what those hours were for.
 - (4) hours of operation to comply with the requirements of the NFPA for firewater pumps {if applicable}
 - (iii) IC engine operations logs, including inspection results, consistent with the requirements of Rule 333.I.
 - (iv) If an operator's tag number is used in lieu of an IC engine identification plate, documentation which references the operator's unique IC engine ID number to a list containing the make, model, serial number, rated maximum BHP and the corresponding RPM.
 - (v) For each engine with timing retard, a District Form –10 (*IC Engine Timing Certification Form*) must be completed each time the engine is serviced.

- (vi) Fuel purchase records or a written statement on the fuel supplier's letterhead signed by an authorized representative of the company confirming that the fuel purchased is either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above (*Reference Stationary Diesel ATCM and Title 13, CCR, Sections 2281 and 2282*).
- e. **Reporting:** On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: *District Rules 202, 205.A, 302, 304, 309, 311, 333 and 1303, PTO 9102, ATC/PTO 10038, 40 CFR 70.6, CCR Title 17, Section 93115*]

C.2 Combustion Equipment – Central Process Heater. The following equipment are included in this emissions unit category:

Device Type	APCD DeviceNo
<i>Combustion - External</i>	
Central Process Heater	5353
Central Process Heater (PR)	5353

- (a) **Emission Limits:** Mass emissions from the Central Process Heater listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit. In addition, the following specific emission limits apply:
 - (i) *NO_x Emissions* - Controlled emissions of NO_x from the Central Process Heater shall not exceed 30 ppmvd at 3 percent oxygen or 0.036 lb/MMBtu when fired on either natural gas or propane. Compliance shall be based on source testing.
 - (ii) *CO Emissions* - Controlled emissions of CO from the Central Process Heater shall not exceed 400 ppmvd at 3 percent oxygen or 0.297 lb/MMBtu when fired on either natural gas or propane. Compliance shall be based on source testing.
- (b) **Operational Limits:**
 - (i) *Fuel Use Limits* - ExxonMobil shall comply with the following operating limits:
 - (1) The Central Process Heater shall not use more than: 502,154 standard cubic feet per day; 45.822 million standard cubic feet per quarter; 183.286 million standard cubic feet per year of natural gas as fuel.
 - (2) The Central Process Heater shall not use more than: 64,659 standard cubic feet per day; 0.862 million standard cubic feet per quarter; 3.448 million standard cubic feet per year of propane gas as fuel.

- (ii) *Fuel Gas Sulfur Limit* - The sulfur content of fuel gas combusted in the Central Process Heater shall not exceed 30 ppmv total sulfur calculated as hydrogen sulfide at standard conditions. Compliance shall be based on in-line continuous monitoring. During amine system startups and shutdowns, the total sulfur content of the fuel shall be allowed to increase up to 239 ppmv as hydrogen sulfide at standard conditions. ExxonMobil shall operate the amine based fuel gas sweetening system at all times when combusting fuel gas in the process heater when the fuel source is from a sour production well. The amine system need not operate if the fuel gas to be combusted in the process heater is obtained from a sweet production well containing less than 80 ppmv total sulfur as hydrogen sulfide at standard conditions.
- (iii) *Use of Propane as Fuel Gas* - Propane may be used as an auxiliary fuel gas to the Central Process Heater on a temporary basis only during times when the supply of produced gas is interrupted or when the gas sweetening system is being repaired. The propane shall meet Gas Processors Association specifications for propane (HD-5 grade) and shall have a total sulfur content no greater than 165 ppmv (10 gr/100 scf).
- (c) Monitoring: The equipment in this section are subject to all the monitoring requirements listed in District Rule 342.E, G and I. The test methods In Rule 342.H shall be used. In addition, ExxonMobil shall:
 - (i) *Fuel Meters* - The amount of fuel combusted in the Central Process Heater shall be measured using permanently installed District-approved in-line fuel meter. Alternative methods for determining propane usage may be proposed by ExxonMobil for District review and approval.
 - (ii) *Source Testing* - On a biennial schedule, ExxonMobil shall source test the Central Process Heater according to Condition C.12 (*Source Testing*). More frequent testing may be required, as determined by the District, if full operating loads have not been achieved.
 - (iii) *Propane Fuel Data* - ExxonMobil shall maintain documentation of the sulfur content and higher heating value (as determined by District-approved ASTM methods) of each propane fuel shipment as certified in the fuel suppliers billing vouchers.
 - (iv) *Natural Gas Fuel Data* – ExxonMobil shall monitor the sulfur content of the natural gas fuel using an in-line continuous hydrogen sulfide analyzer. This analyzer shall be operated consistent with the requirements of the District's CEM Protocol document (dated October 22, 1992 and subsequent updates), where applicable. The readings from this analyzer shall be adjusted upward to take into account the average non-hydrogen sulfide reduced sulfur compounds in the fuel gas (if any). ExxonMobil shall implement the District-approved *Fuel Gas Sulfur Reporting Plan* for the life of the project. This Plan shall detail: the monitoring equipment and CEM protocol procedures, the adjustments to the hydrogen sulfide readings due to non-hydrogen sulfide reduced sulfur compounds and the reporting

methods for compliance with the applicable limits. ExxonMobil shall submit the lab analyses reports to the District.

- (d) Recordkeeping: The equipment listed in this section are subject to all recordkeeping requirement listed in Rule 342.I. In addition, ExxonMobil shall:
- (i) *Natural Gas Fuel Use* - Daily, quarterly and annual fuel use for the Central Process Heater in units of standard cubic feet.
 - (ii) *Sulfur Content* - A monthly log of the total sulfur content of the natural gas and propane combusted as fuel gas.
 - (iii) *Propane Fuel Gas Use* - Record in a log each usage of propane in a District-approved format and maintain documentation of the sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers.
- (e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in District Rule 342.J. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: District Rules 311, 342 and 1303, PTO 9102, ATC/PTO 10038, 40 CFR 70.6]

C.3 **Combustion Equipment - Flare.** The following equipment are included in this emissions unit category:

Device Type	APCD DeviceNo
<i>Flare Relief System (Table J)</i>	
Purge and Pilot	102382
Planned - Continuous	102383
Planned - Other	102384
Unplanned	102385

- (a) Emission Limits: Mass emissions from the flare relief system listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Notwithstanding the above and consistent with District P&P 6100.004, the short-term emission limits for *Planned - Other* and *Unplanned - Other* flaring categories in Table 5.1 shall not be considered as enforceable limits. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit.

Continuous planned flaring emissions are assumed for the flare header based on one-half the minimum detection limit for the meter according to manufacturer minimum velocity detection limits (0.25 fps). Other than flare purge and pilot, this is the only continuous flaring allowed under this permit.

- (b) Operational Limits:

- (i) *Flaring Volumes* - Flaring volumes from the purge and pilot, planned continuous, planned other and unplanned other events shall not exceed the following volumes:

Flare Category	Hourly (10 ³ scf)	Daily (10 ³ scf)	Quarterly (10 ⁶ scf)	Annual (10 ⁶ scf)
Purge/Pilot	0.445	10.68	0.974	3.898
Planned Continuous	0.607	14.568	1.329	5.317
Planned Other			1.575	6.3
Unplanned Other			8.5	34

- (ii) *Flare Purge/Pilot Fuel Gas Sulfur Limits* - The purge/pilot fuel gas combusted in the flare shall not exceed a total sulfur content of 30 ppmv. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.
 - (iii) *Flare Planned Continuous Flaring Sulfur Limits* - The sulfur content of all gas burned as continuous flaring in the flare header shall not exceed 20,000 ppmv total sulfur. This limit shall be enforced on an average quarterly basis (i.e., the average of all sulfur content measurements during the quarter). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.
 - (iv) *Rule 359 Technology Based Standards* - ExxonMobil shall comply with the technology based standards of Rule 359.D.2. Compliance shall be based on monitoring and recordkeeping requirements of this permit as well as District inspections.
 - (v) *Flaring Modes* - ExxonMobil shall operate the flare consistent with District P&P 6100.004 (*Planned and Unplanned Flaring Events*). If ExxonMobil is unable to comply with the infrequent planned flaring limit of 4 events per year from the same processing unit or equipment type, then an ATC permit application shall be submitted to incorporate those emissions in the short-term (hourly and daily) emissions of Table 5.3.
 - (vi) *Rule 359 Planned Flaring Target Volume Limit* - Pursuant to Rule 359, ExxonMobil shall not flare more than 66 million standard cubic feet per month during planned flaring events.
 - (vii) *Use of Propane as Fuel Gas* - Propane may be used as an auxiliary fuel gas to the flare purge/pilot on a temporary basis only during times when the supply of produced gas is interrupted or when the gas sweetening system is being repaired. The propane shall meet Gas Processors Association specifications for propane (HD-5 grade) and shall have a total sulfur content no greater than 165 ppmv (10 gr/100 scf).
- (c) **Monitoring:** The equipment in this section are subject to all monitoring requirements listed in District Rule 359.G. The test methods In Rule 359.E. shall be used. In addition, ExxonMobil shall:

- (i) *Flare Volumes* - The volumes of gas flared during each planned event shall be monitored by use of District-approved flare header flow meters. Unplanned flaring shall be monitored on an aggregate basis and shall be the difference between the total flare volume and the volume of gas flared during planned flaring events. The meters shall be calibrated and operated consistent with ExxonMobil's District approved *Process Monitor Calibration and Maintenance Plan*. An event is defined as any flow recorded by the flare header flow meters that exceeds the event flow rate thresholds listed below where the duration is 60 seconds or greater. During an event, any subsequent flows recorded by the flare header flow meter within 5 minutes after the flow rate drops below the minimum detection level of the meter shall be considered as part of the event.

Flare Header	Event Flow Rate Threshold (scfh)	Meter Minimum Detection Level (scfh)
Flare (FE-134-2,-3)	1,503	1,503

- (1) All planned flaring not classified as an event pursuant to the above definition shall be aggregated as a single quarterly volume and recorded in the *Planned Other* flaring category. Notwithstanding the above definition of an event, continuous flaring is prohibited for the *Planned Other* and *Unplanned Other* flaring categories.
- (ii) *Purge/Pilot Gas* - ExxonMobil shall continuously monitor the purge/pilot fuel gas using H₂S analyzer. ExxonMobil shall also perform annual total sulfur content and HHV measurements of the fuel gas using ASTM or other District-approved methods. ExxonMobil shall utilize District-approved sampling and analysis procedures.
- (iii) *Flaring Sulfur Content* - The hydrogen sulfide content of produced gas combusted during flaring events shall be measured on the schedule pursuant to the District-approved *Flare Gas Sulfur Reporting Plan* using District-approved ASTM methods. On an annual basis, ExxonMobil shall also measure the non-hydrogen sulfide reduced sulfur compounds and these values shall be added to the hydrogen sulfide measurements to obtain the total sulfur content. ExxonMobil shall perform additional testing of the sulfur content and hydrogen sulfide content, using approved test methods, as requested by the District.
- (1) ExxonMobil shall sample the flare header to determine the hydrogen sulfide content using sorbent tubes. To obtain the total sulfur content, ExxonMobil shall add the prior year's non-hydrogen sulfide reduced sulfur compounds analysis result to the absorbent tube readings.
- (iv) *Pilot Flame Detection* - ExxonMobil shall continuously monitor each pilot to ensure that a flame is present at each pilot at all times.
- (v) *Propane Fuel Data* - ExxonMobil shall maintain documentation of the sulfur content and higher heating value (as determined by District-approved ASTM methods) of each propane fuel shipment as certified in the fuel suppliers billing vouchers.

- (d) **Recordkeeping:** The equipment listed in this section is subject to all recordkeeping requirements listed in Rule 359.H. In addition, ExxonMobil shall:
- (i) *Flare Event Logs* - All planned flaring events shall be recorded in a log. The log shall include: date; duration of flaring events (including start and stop times); quantity of gas flared; total sulfur content; hydrogen sulfide content; high heating value; reason for each planned flaring event, including the processing unit or equipment type involved; the total heat input (MMBtu) per event; and, the type of event (e.g., Planned - Continuous LP, Planned - Other). The volumes of gas combusted and resulting mass emissions of all criteria pollutants for each type of event shall also be summarized for a cumulative summary for each day, quarter and year.
 - (ii) The total volume of gas combusted and resulting in mass emissions of all criteria pollutants from unplanned flaring events shall be summarized for each quarter and year.
 - (iii) *Pilot/Purge Gas Volume* - The volume of pilot/purge fuel gas combusted in the flare shall be recorded on a weekly, quarterly and annual basis.
 - (iv) *Infrequent Flaring Events* - ExxonMobil shall track and log the number of planned infrequent flaring events (as defined by District P&P 6100.004) from each processing unit or equipment type in a manner approved by the District.
 - (v) *Propane Fuel Gas Use* - Record in a log or electronic file each usage of propane in a District-approved format and maintain documentation of the sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers.
- (e) **Reporting:** The equipment listed in this section are subject to all reporting requirements listed in District Rule 359.H. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: District Rules 359 and 1303, PTO 9102, ATC/PTO 11236, 40 CFR 70.6]

C.4 **Fugitive Hydrocarbon Emissions Components.** The following equipment are included in this emissions unit category:

Device Type	Device Subtype	APCD DeviceNo
<i>Fugitive Components - Gas</i>		
Valve/Connection	Accessible	102526
Valve/Connection	Category B	102527
Valve/Connection	Category C	104948
Valve/Connection	Category F	104943
Valve/Connection	Unsafe	102529
	Exempt	102536

Device Type	Device Subtype	APCD DeviceNo
<i>Fugitive Components - Oil</i>		
Valve/Connection	Accessible	102516
Valve/Connection	Category B	102520
Valve/Connection	Category F	102517
Valve/Connection	Unsafe	104950
Pump Seal	Dual/Tandem	102518
	Exempt	102525

- (a) Emission Limits: Mass emissions from the gas/light liquid service (sub-total) and oil service (sub-total) components listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with this condition shall be based on actual component-leakpath counts as documented through the monitoring, recordkeeping and reporting conditions in this permit.
- (b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rule 331.D and E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition ExxonMobil shall meet the following requirements:
- (i) *VRS Use* - The vapor recovery and gas collection (VR & GC) systems at Platform Heritage shall be in operation when equipment connected to these systems are in use. These systems include piping, valves, and flanges associated with the VR & GC systems. The VR & GC systems shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.
 - (ii) *I&M Program* - The District-approved I&M Plan, *Fugitive Emissions Inspection and Maintenance Program for Platforms Heritage and Harmony* shall be implemented for the life of the project. The Plan, and any subsequent District approved revisions, is incorporated by reference as an enforceable part of this permit.
 - (iii) *Leakpath Count* - The total component-leakpath count listed in ExxonMobil's most recent I&M component-leakpath inventory shall not exceed the component-leakpath sub-totals listed in Table 5.1 by more than five percent. This five percent range is to allow for minor differences due to component counting methods and does not constitute allowable emissions growth due to the addition of new equipment.
 - (iv) *Venting* - All routine venting of hydrocarbons shall be routed to either the main gas compressors, flare header, injection wells or other District-approved control device.
 - (v) *BACT* - ExxonMobil shall apply BACT, as defined in Table 4.1 Table 4, to all component-leakpaths in hydrocarbon service for Gas Compressor Skid Unit CZZ-306, the Topsides Installation Project (ATC 9828), and the Amine Fuel Gas Treating System for the life of the project.
 - (vi) *Rule 331 BACT* - The component-leakpaths in hydrocarbon service listed in Table 4.2 are subject to BACT requirements pursuant to Rule 331. BACT, as defined in Table 4.2, shall be implemented for the life of the project.
 - (vii) *Category B Requirements* - Component-leakpaths monitored quarterly at less than 500 ppmv shall achieve a mass emission control efficiency of 85 percent. Category B component-leakpaths are defined as component-leakpaths associated with closed vent systems (e.g., vapor recovery systems) for which screening

values are maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. Category B component-leakpaths also include components subject to enhanced fugitive inspection and maintenance programs for which screening values are also maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. For Category B components, screening values above 500 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

- (viii) *Category C Requirements* - Component-leakpaths monitored quarterly at less than 100 ppmv shall achieve a mass emission control efficiency of 87 percent. Category C component-leakpaths are defined as component-leakpaths subject to enhanced fugitive inspection and maintenance programs for which screening values are maintained at or below 100 ppmv as methane, monitored per EPA Reference Method 21. For Category C components, screening values above 100 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.
- (ix) *Category F Requirements* - Low emitting design component-leakpaths monitored quarterly at less than 100 ppmv shall achieve a mass emission control efficiency of 90 percent. Category F component-leakpaths are subject to BACT per Rule 331 for which screening values are maintained at or below 100 ppmv as methane, monitored per EPA Reference Method 21. For Category F components, screening values above 100 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in District Rule 331.F. The test methods in Rule 331.H shall be used.

- (i) *ERCs for Platform Heritage Low/Intermediate Pressure and High Pressure Projects* - ExxonMobil shall perform quarterly monitoring on a minimum of 118 standard (i.e., non-bellows seal and non-low emissions) valves and a minimum of 370 standard flanges/connections at 100 ppmv leak detection threshold. These monitoring requirements must be fulfilled in order to generate 0.115 tpq of ROC ERCs of the total required for projects permitted by ATC 11132 Mod-01. These components are listed in a separate table in ExxonMobil's District approved I&M Plan. ExxonMobil shall replace any component on the list with a replacement if the component is no longer in hydrocarbon service. The District shall be notified, in writing, of all such replacements within ninety (90) days after the replacement. The notification shall include complete equipment description information equivalent to the table in ExxonMobil's District approved I&M Plan and the reason for the replacement. Subsequent I&M records and reports shall include the replacement component(s).

(d) Recordkeeping: The equipment listed in this section are subject to all the recordkeeping requirements listed in District Rule 331.G. In addition, ExxonMobil shall:

- (i) *I&M Log* - ExxonMobil shall record in a log the following: a record of leaking components found (including name, location, type of component, date of leak detection, the ppmv or drop-per-minute reading, date of repair attempts, method of

detection, date of re-inspection and ppmv or drop-per-minute reading following repair); a record of the total components inspected and the total number and percentage found leaking by component type; a record of leaks from critical components; a record of leaks from components that incur five repair actions within a continuous 12-month period; and, a record of component repair actions including dates of component re-inspections. For the purpose of this paragraph, a leaking component is any component which exceeds the applicable limit:

- (1) greater than or equal to 1,000 ppmv for minor leaks under Rule 331 (includes Accessible/Inaccessible components and Category A components);
 - (2) greater than or equal to 100 ppmv for components subject to current BACT (includes Bellows, Category F and Category G)
 - (3) greater than 100 ppmv for components subject to enhanced fugitive inspection and maintenance programs (Category C and Category E)
 - (4) greater than or equal to 500 ppmv for components subject to enhanced fugitive inspection and maintenance programs (Category B and Category D)
- (e) **Reporting:** The equipment listed in this section are subject to all reporting requirements listed in District Rule 331.G. Within one calendar quarter whenever there is a change in the component list or diagrams, ExxonMobil shall provide an updated fugitive hydrocarbon component inventory per Rule 331.I. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: *District Rules 331 and 1303, ATC 9828, ATC 9634, PTO 9634, PTO 9102, ATC/PTO 10038, ATC 11132 Mod-02, 40 CFR 70.6*]

C.5 Crew and Supply Boats. The following equipment are included in this emissions category:

Device Type	APCD DeviceNo	Device Type	APCD DeviceNo
<i>Crew Boat</i>		<i>Supply Boat</i>	
Main Engine - DPV	5361	Main Engine - DPV	5357
Main Engine - Spot Charter	104960	Main Engine - Spot Charter	104959
Auxilliary Engine - DPV	5362	Generator Engine - DPV	5358
		Bow Thruster - DPV	5359
<i>M/V Broadbill</i>		Winch - DPV	104962
Main Engine - DPV	107900		
Auxilliary Engine - DPV	107901	Emergency Response	5360
<i>Survival Capsules</i>			
Survival Capsule #1	103956		
Survival Capsule #2	103957		
Survival Capsule #3	103958		

- (a) Emission Limits: Mass emissions from the crew, supply and emergency response boats listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with the quarterly and annual mass emission limits for the main engines on the Dedicated Project Vessel (“DPV”) and spot charter crew and supply boat main engines shall be based on the subtotal emission limits in Table 5.4. Compliance with the quarterly and annual mass emission limits for the auxiliary engines on the DPV (including the *Broadbill*) crew boats shall be based on the subtotal emission limits in Table 5.4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit. In addition:
- (i) *NO_x Emissions* - Except as provided below, controlled emissions of NO_x from each diesel fired main engine in each DPV crew and supply boat shall not exceed 337 lb /1000 gallons (8.4 g/bhp-hr). Spot charter crew and supply boats shall not be required to comply with this controlled NO_x emission rate. Controlled emissions of NO_x from the Tier II diesel fired main propulsion engines on the *M/V Broadbill* crew boat, shall not exceed 218.98 lb/kgal (5.46 g/bhp-hr). Controlled emissions of NO_x from the Tier II diesel fired auxiliary engines on the *M/V Broadbill* crew boats, shall not exceed 217.87 lb/kgal (5.44 g/bhp-hr). Compliance shall be based on annual source testing consistent with the requirements listed in this permit and DOI 0042 Mod - 01.
 - (ii) *Crew, Supply and Emergency Response Boat Stationary Source Maximum Permitted Emissions* - To more accurately define the *ExxonMobil – SYU Project* Stationary Source’s annual potential-to-emit (which is used to determine fees for Air Quality Plans (Rule 210.F)), crew boat, supply boat (including spot charters) and emergency response boat usage, in aggregate, associated with OCS Platforms Heritage and Harmony shall not exceed the annual emission limits shown in Table 5.2. These limits apply to the crew boats, supply boats and emergency response boats separately.
- (b) Operational Limits: Operation of the equipment listed in this section shall not exceed the limits listed below. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. The fuel use limits in items (i) – (iv) below apply to the crew and supply boats while operating within 25-miles of the ExxonMobil – SYU platforms. For compliance with the limits in (i) – (iv) below, all the fuel use within 25-miles of the ExxonMobil – SYU platforms shall be assigned according the District-approved *Boat Monitoring and Reporting Plan*.
- (i) *Crew Boat Main Engine Limits* - The combined DPV and spot charter crew boat main engines for Platform Heritage shall not use more than: 65,307 gallons per quarter; 261,227 gallons per year of diesel fuel.
 - (1) The DPV and spot charter crew boat main engines for platform Heritage shall each not use more than 3,916 gallons per day.
 - (ii) *Crew Boat Auxiliary Engine Limits* - The crew boat auxiliary engines for Platform Heritage shall not use more than: 156 gallons per day; 10,087 gallons per quarter; 40,348 gallons per year of diesel fuel.

- (iii) *M/V Broadbill Crew Boat Operational Requirements* – ExxonMobil shall use the *M/V Broadbill* for at least forty percent (40%) of all crew boat trips to the platforms each year. Compliance with this condition will be determined each calendar year based on total fuel usage from the *M/V Broadbill* and fuel usage from all DPV crew boats supporting the ExxonMobil – SYU platforms.
- (iv) *Supply Boat Main Engine Limits* - The combined DPV and spot charter supply boat main engines for Platform Heritage shall not use more than: 66,350 gallons per quarter; 265,399 gallons per year of diesel fuel.
 - (1) The DPV and spot charter supply boat main engines for platform Heritage shall each not use more than 3,146 gallons per day
- (v) *Supply Boat Auxiliary Engine Limits* - The combined uncontrolled generator, bow thruster, and winch supply boat engines for Platform Heritage shall not use more than: 392 gallons per day; 9,521 gallons per quarter; 38,084 gallons per year of diesel fuel.
- (vi) *Emergency Response Boat Engine Limits* - The emergency response boat engines shall not use more than: 12,500 gallons per quarter; 50,000 gallons per year of diesel fuel. ExxonMobil's allocation of allowable emergency response boat fuel usage for OCS Platforms Heritage, Heritage and Hondo shall not exceed: 1,137 gallons per quarter; 4,546 gallons per year of diesel fuel.
- (vii) *Crew, Supply and Emergency Response Boat Stationary Source Operational Limits* - To more accurately define the ExxonMobil – SYU Project Stationary Source's annual potential-to-emit (which is used to determine fees for Air Quality Plans (Rule 210.F)), crew boat, supply boat (including spot charters) and emergency response boat usage, in aggregate, associated with OCS Platforms Heritage and Harmony shall not exceed the annual fuel use limits shown in items (i), (ii), (iii), (iv) and (v) above. These limits apply to the crew boat main engines, crew boat auxiliary engines, supply boat main engines, supply boat auxiliary engines and emergency response boat engines separately.
- (viii) *Spot-Charter Limits* - The number of allowable annual spot charter crew boat trips shall not exceed ten percent of the actual annual number of trips made by the DPV crew boats. The number of allowable annual spot charter supply boat trips shall not exceed ten percent of the actual annual number of trips made by DPV supply boats. Compliance shall be based on a comparison of the main engine fuel use for DPV and spot charter boats (i.e., the total main engine spot charter supply boat fuel use must be less than 10 percent of the total main engine DPV supply boat fuel use and the total main engine spot charter crew boat fuel use must be less than 10 percent of the total main engine DPV crew boat fuel use).
- (ix) Crew, supply and spot charter boats shall be for the activities specified in 2.2.3. Any boats for or in support of activities not specified in Section 2.2.3 will be considered as new projects, and the boat emissions associated with such projects

will be considered in the project potential to emit. Supply boats shall not use the Ellwood pier for transfer of personnel in place of crew boats.

- (ix) *Fuel and Fuel Additive Requirements* - The permittee may only add CARB Diesel, or an alternative diesel fuel that meets the requirements of the ATCM Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the ATCM Verification Procedure, or any combination of the above to each engine or any fuel tank directly attached to each engine.
- (x) *New/Replacement Boats* - With the exception of the *M/V Broadbill* crew boat, ExxonMobil may utilize any new/replacement project (DPV) boat without the need for a permit revision if that boat meets the following conditions:
 - (1) The main engines are of the same or less bhp rating; and
 - (2) The combined pounds per day potential to emit (PTE) of all generator and bow thruster engines is the same or less than the sum of the pounds per day PTE for these engines as determined from the corresponding Table 5.1-3 emission line items of this permit; and
 - (3) The NO_x, ROC, CO, PM and PM₁₀ emission factors are the same or less for the main and auxiliary engines. For the main engines, NO_x emissions must meet the 337 lb/1000 gallons emission standard.
 - (4) The above criteria also apply to spot charter boats, except for the NO_x emission standard noted in (3) above. Any proposed new/replacement crew, supply or spot charter boat that does not meet the above requirements (1) - (3) shall first obtain a permit revision prior to operating the boat. The District may require manufacturer guarantees and emission source tests to verify this NO_x emission standard.
 - (5) ExxonMobil shall revise the Boat Monitoring and Reporting Plan, obtain District approval of such revisions and implement the revised Plan prior to bringing any new/replacement boat into service, except for the use of spot charters. If a new spot charter is brought into service then ExxonMobil shall revise and resubmit the boat plan within thirty (30) calendar days after it is first brought into service. If the fuel metering and emissions computation procedures for a new spot charter are identical to a boat that is already addressed in the approved boat plan, a letter addendum stating this will suffice for the revision/re-submittal of the boat plan.
- (xi) Prior to bringing the boat into service for the first time, ExxonMobil shall submit the information listed below to the District for any new/replacement crew and supply boat that meets the requirements set forth in (1) - (3) above, and for new spot charters that have not been previously used on the *ExxonMobil – SYU Project*. For spot charters, this information shall be submitted within thirty (30) calendar days after the boat is first brought into service. ExxonMobil shall notify the District Project Manager (via fax or e-mail) within three (3) calendar days after a new spot charter is first brought into operation. Any boat put into service that does

not meet the requirements above, as determined by the District at any time, shall immediately cease operations and all prior use of that boat shall be considered a violation of this permit.

- (1) Boat description, including the type, size, name, engine descriptions and emission control equipment.
 - (2) Engine manufacturers' data on the emission levels for the various engines and applicable engine specification curves.
 - (3) A quantitative analysis using the operating and emission factor assumptions given in tables 5-1 and 5-2 of this permit that demonstrates criteria (b) above is met.
 - (4) Estimated fuel usage within 25-miles of Platform Hondo.
 - (5) Any other information the District deems necessary to ensure the new boat will operate consistent with the analyses that form the basis for this permit.
- (xii) *Validity of ERCs* - The ERCs generated by DOI 0042 Mod - 01 are valid only for the *M/V Broadbill* crew boat and the associated newly installed Tier II main propulsion and auxiliary engines. Any alteration to the engines installed in the *M/V Broadbill* or alteration to the actual crew boat operated by ExxonMobil shall require a modification to the DOI and to the underlying ATC to re-analyze the validity of the ERCs. If the District determines that the ERCs are no longer valid, then ExxonMobil shall provide substitute ERCs and apply for necessary permit modifications.
- (c) Monitoring: ExxonMobil shall fully implement the District approved *Boat Monitoring and Reporting Plan* for the life of the project, and shall obtain District approval for any proposed updates or modifications to the Plan. This plan documents the recordkeeping and reporting procedures for boat activity, fuel usage, and emissions.
- (i) ExxonMobil may use alternative methods (including location methods) for documenting and reporting boat activity, fuel usage and emissions, provided these methods are approved by the District as being equivalent in accuracy and reliability to those of the District's *Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document (dated June 21, 1991).
 - (ii) Spot charter boats shall, at a minimum, track total fuel usage on a per day basis using District-approved procedures. These data shall be submitted in a District-approved format to the District.
- (d) Recordkeeping: The following records shall be maintained in legible logs and shall be made available to the District upon request:
- (i) *Maintenance Logs* - For all main and auxiliary engines on DPV crew and DPV supply boats, maintenance log summaries that include details on injector type and timing, setting adjustments, major engine overhauls, and routine engine

maintenance. These log summaries shall be made available to the District upon request. For each main and auxiliary engine with timing retard, a District Form – 10 (*IC Engine Timing Certification Form*) must be completed each time the engine is serviced.

- (ii) *Crew Boat Fuel Usage* - Daily, monthly, quarterly and annual fuel use for crew boat main engines and auxiliary engines while operating within 25-miles of the platform, itemized by DPV and spot charter boats. In addition, the fuel use must be summarized for all crew boats by main and auxiliary engines.
- (iii) *Supply Boat Fuel Usage* - Daily, monthly, quarterly and annual fuel use for supply boat main engines and auxiliary engines while operating within 25-miles of the platform, itemized by DPV and spot charter boats. In addition, the fuel use must be summarized for all supply boats by main and auxiliary engines.
- (iv) *Emergency Response Boat Fuel Usage* - Total quarterly and annual fuel use for the emergency response boat and Platform Heritage's allocation of that total.
- (v) The sulfur content of each fuel shipment delivered to the boats as documented by fuel supplier records (e.g., billing vouchers, or bills of lading).
- (e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all crew, supply and spot charter boat data required by the *Compliance Verification Reports* condition of this permit:
 - (i) If, at any time, the District determines that logs or reports indicate fuel use greater than the limits of Condition 9.C.1(b) of this permit, ExxonMobil shall restrict its vessel activities to ensure that emissions do not exceed total quarterly emissions allowed in the permit, or shall submit an application for and obtain a permit providing additional offsets. Such offsets shall be in place no later than the start of the next quarter. [Re: District Rule 1303, PTO 9102, ATC/PTO 10038, ATC/PTO 10169, ATC/PTO 10738, ATC/PTO 10800, ATC/PTO 11236, ATC 11986, 40 CFR 70.6]

C.6 **Pigging Equipment.** The following equipment are included in this emissions category:

Device Type	APCD DeviceNo
<i>Pigging Equipment (Table F)</i>	
Emulsion Pig Launcher	102539
Gas Pig Launcher	102540

- (a) Emission Limits: Mass emissions from the emulsion and gas pig receivers and launchers listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit.

- (b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rule 325.E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition ExxonMobil shall meet the following requirement:
- (i) *Events* - The number of emulsion and gas pig operations (events) shall not exceed the maximum operating schedule listed in Table 5.1.
 - (ii) *Pressure* - Prior to opening a pig receiver/launcher, the receiver launcher shall be depressurized to the vapor recovery system or flare to the maximum extent feasible until the receiver/launcher reaches a pressure 1 psig or less. Prior to opening the pig receiver/launcher, ExxonMobil shall purge the vessel with water (optional) and inert or sweet produced gas (not to exceed 30 ppmv total sulfur content calculated as H₂S at standard conditions, and not greater than 23 lbs/lb-mole and 30% (by weight) ROC) and then bleeding the vessel to the vapor recovery system or flare. At no time shall the pig receiver/launcher hatch be opened when the pressure in the receiver/launcher is greater than 1 psig. Compliance shall be based on a test gauge or equivalent District-approved monitor installed to monitor the internal pressure of the receiver/launcher. Pressure readings shall be recorded prior to each opening of the receiver/launcher.
 - (iii) *Openings* - Access openings to the pig receiver/launcher shall be kept closed at all times, except when a pipeline pig is being placed into or removed from the receiver/launcher.
- (c) Monitoring: ExxonMobil shall monitor the pressure inside the pig receivers and launchers with a District-approved pressure test gauge or equivalent District-approved monitor installed to determine the internal pressure of the receiver/launcher.
- (d) Recordkeeping: ExxonMobil shall record in a log the date of each pigging operation and the pressure inside the receiver/launcher prior to each opening.
- (e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: *District Rules 325 and 1303, PTO 9102, ATC 9828, ATC/PTO 10038, 40 CFR 70.6*]

C.7 **Tanks/Sumps/Separators.** The following equipment are included in this emissions category:

Device Name	ExxonMobil ID	KVB Service	APCD DeviceNo
<i>Group A Units</i>			
Open Drain Sump	ABH-406	2° heavy oil	5364
Wellbay Drain Sump	ABH-405	2° heavy oil	5365
Skim Pile	ABH-416	2° heavy oil	5367
Drilling Settling Tank	ABJ-417	2° heavy oil	5368
<i>Group B Units</i>			
Closed Drain Sump	MBH-132	2° heavy oil	5363
Amine Sump	MBH-170	2° heavy oil	5366
Emulsion Surge Tank	MEJ-110	2° heavy oil	107171
<i>Group C Units</i>			
Chemical Storage Tote Tanks			102381

- (a) Emission Limits: Mass emissions from the equipment listed above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit.
- (b) Operational Limits: All process operations from the Group A equipment listed in this section shall meet the requirements of District Rule 325, Sections D.3, D.4, E, F and G. All process operations from the Group B equipment listed in this section shall meet the requirements of District Rule 325, Sections F.5 and F.6. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, ExxonMobil shall:
- (i) *VRS Use* - The vapor recovery systems shall be in operation when the equipment connected to the VRS systems at the facility are in use. The VRS system includes piping, valves, and flanges associated with each VRS system. Each VRS system shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.
 - (ii) *Vapor Recovery System Efficiency* - The vapor recovery system maintain a minimum efficiency of 95 percent (mass basis). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.
 - (iii) *Service Type Restrictions* - The KVB service type, as defined pursuant to District P&P 6100.060, for each Group A and Group B unit shall be restricted to the service type listed above or a service of a lesser emitting type (e.g., a secondary heavy oil sump may be used as a tertiary heavy oil sump).
 - (iv) *Rule 326 Applicability* - ExxonMobil shall not use any tank, container or vessel that is subject to the requirements of Rule 326 without first obtaining an ATC permit from the District for such use.

- (c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements of District Rule 325.H (for Group A units only). The test methods outlined in District Rule 325.G shall be used, as applicable.
- (d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in District Rule 325.F. In addition, ExxonMobil shall maintain logs for the information listed below. These logs shall be made available to the District upon request:
 - (i) On a monthly basis, the total oil emulsion and produced gas production along with the number of days per month of production.
- (e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in District Rule 325.I. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: *District Rules 325 and 1303, PTO 9102, 40 CFR 70.6*]

C.8 Solvent Usage. The following equipment are included in this emissions unit category:

Device Type	APCD DeviceNo
Solvent Usage Cleaning/Degreasing	5369

- (a) Emission Limits: Mass emissions from the solvent usage shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance shall be based on the operational, recordkeeping and reporting requirements of this permit. For short-term emissions, compliance shall be based on monthly averages.
- (b) Operational Limits: Use of solvents for cleaning, degreasing, thinning and reducing shall conform to the requirements of District Rules 317, 321 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and facility inspections. In addition, ExxonMobil shall comply with the following:
 - (i) *Containers* - Vessels or containers used for storing materials containing organic solvents shall be kept closed unless adding to or removing material from the vessel or container.
 - (ii) *Materials* - All materials that have been soaked with cleanup solvents shall be stored, when not in use, in closed containers that are equipped with tight seals.
 - (iii) *Solvent Leaks* - Solvent leaks shall be minimized to the maximum extent feasible or the solvent shall be removed to a sealed container and the equipment taken out

of service until repaired. A solvent leak is defined as either the flow of three liquid drops per minute or a discernable continuous flow of solvent.

- (iv) *Reclamation Plan* - ExxonMobil shall abide by the procedures identified in the District approved Solvent Reclamation Plan that describes the proper disposal of any reclaimed solvent. All solvent disposed of pursuant to the District approved Plan will not be assumed to have evaporated as emissions into the air and, therefore, will not be counted as emissions from the source. The Plan details all procedures used for collecting, storing and transporting the reclaimed solvent. Further, the ultimate fate of these reclaimed solvents must be stated in the Plan.

(c) Monitoring: none

- (d) Recordkeeping: ExxonMobil shall record in a log the following on a monthly basis for each solvent used: amount used; the percentage of ROC by weight (as applied); the solvent density; and the amount of solvent reclaimed for District-approved disposal according to the District-approved *Solvent Reclamation Plan*. Based on the District approved Solvent Reclamation Plan, ExxonMobil shall also record whether the solvent is photochemically reactive; and, the resulting emissions of ROC to the atmosphere in units of pounds per month and the resulting emissions of photochemically reactive solvents to the atmosphere in units of pounds per month. Product sheets (MSDS or equivalent) detailing the constituents of all solvents shall be maintained in a readily accessible location at Platform Heritage.

- (e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [Re: *District Rules 317, 321, 324 and 1303, PTO 9102, ATC/PTO 10038, 40 CFR 70.6*]

C.9 **Recordkeeping.** All records and logs required by this permit and any applicable District, state or federal rule or regulation shall be maintained for a minimum of five calendar years from the date of information collection and log entry at the platform. These records or logs shall be readily accessible and be made available to the District upon request. [Re: *District Rule 1303, PTO 9102, ATC 9634, PTO 9634, ATC 9828, ATC/PTO 10038, 40 CFR 70.6*]

C.10 **Semi-Annual Compliance Verification Reports.** Twice a year, ExxonMobil shall submit a compliance verification report to the District. Each report shall document compliance with all permit, rule or other statutory requirements during the prior two calendar quarters. The first report shall cover calendar quarters 1 and 2 (January through June) and the second report shall cover calendar quarters 3 and 4 (July through December). The reports shall be submitted by March 1st and September 1st each year. Each report shall contain information necessary to verify compliance with the emission limits and other requirements of this permit and shall document compliance separately for each calendar quarter. These reports shall be in a format approved by the District. Compliance with all limitations shall be documented in the submittals. All logs and other basic source data not included in the report shall be made available to the District upon request. The second report shall also include an annual report for the prior four quarters. Pursuant to Rule 212, a completed *District Annual Emissions Inventory* questionnaire should be included in the annual report or submitted electronically via the District website. ExxonMobil

may use the Compliance Verification Report in lieu of the Emissions Inventory questionnaire if the format of the CVR is acceptable to the District's Emissions Inventory Group and if ExxonMobil submits a statement signed by a responsible official stating that the information and calculations of quantifies of emissions of air pollutants presented in the CVR are accurate and complete to best knowledge of the individual certifying the statement. The report shall include the following information:

(a) *Internal Combustion Engines.*

- (i) The daily, quarterly and annual operating hours (or fuel use) data for each pedestal crane engine and for each cement and cuttings reinjection pump engine, in units of hours (or gallons).
- (ii) Emergency use hours of operation for each emergency generator and firewater pump.**
- (iii) Maintenance and testing hours of operation for each emergency generator and firewater pump.**
- (iv) Hours of operation for all uses other than for emergency use and maintenance and testing, along with a description of what those hours were for each emergency generator and firewater pump.**
- (v) A statement that all fuel delivered to the boats or the platform was CARB diesel (Records may be requested by the District).
- (vi) On an annual basis, the heating value of all diesel fuel, in units of Btu/gal.
- (vii) Documentation of any equivalent routine engine replacement.

**District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*) can be used for requirements (2)-(4).

(b) *Central Process Heater.*

- (i) The daily, quarterly and annual fuel use for the Central Process Heater in units of standard cubic, broken down by natural gas and propane.
- (ii) The monthly total sulfur content of the natural gas and propane combusted as fuel gas.

(c) *Flare.*

- (i) The volumes of gas combusted and resultant mass emissions for each flare category (i.e., Purge/Pilot; Continuous – LP; Continuous – AG; Planned Other; Planned - Other), shall be presented as a cumulative summary for each day, quarter and year. Unplanned flaring shall be presented as a cumulative summary for each quarter and year only.

- (ii) The highest total sulfur content and hydrogen sulfide content observed each week in the flare header.
 - (iii) The monthly total sulfur content of flare purge and pilot fuel gas.
 - (iv) A copy of the Flare Event Log for the reporting period. Include a separate listing of all planned infrequent events that occurred more than four times per year from the same cause from the same processing unit or equipment type.
- (d) *Fugitive Hydrocarbons.* Rule 331/Enhanced Monitoring fugitive hydrocarbon I&M program data (on a quarterly basis):
 - (i) Inspection summary which includes a record of the total components inspections and the total number and percentage found leaking by component type, inspection frequency, and leak detection threshold (i.e. the component “Category” as defined in District Permit Guideline Document 15). The record shall also specify leaks from critical components.
 - (ii) Record of leaking components and associated component repair actions including dates of component re-inspections. Critical components shall be identified in the record.
 - (iii) Listing of components installed as BACT during the reporting year as approved by the District.
- (e) *Crew and Supply Boats.*
 - (i) Daily, quarterly and annual fuel use for the crew boat main engines and auxiliary engines for the three operating scenarios defined in the District-approved Boat Monitoring and Reporting Plan. The three scenarios include crew boat operations within 25 miles of Platform Heritage, within 3 miles of shore, and within Santa Barbara County. The report will be itemized by DPV boat usage and spot charter boat usage. In addition, the fuel use must be summarized for all crew boats by main and auxiliary engines.
 - (ii) Daily, quarterly and annual fuel use for the supply boat main engines and auxiliary engines (including the bow thruster engine) for the three operating scenarios defined in the District-approved Boat Monitoring and Reporting Plan. The three scenarios include supply boat operations within 25 miles of Platform Heritage, within 3 miles of shore, and within Santa Barbara County. The report will be itemized by DPV boat usage and spot charter boat usage. In addition, the fuel use must be summarized for all supply boats by main and auxiliary engines.
 - (iii) A statement that all diesel fuel delivered to the boats or the platform was CARB diesel.
 - (iv) Information regarding any new project boats servicing ExxonMobil’s OCS platforms as detailed in Permit Condition 9.C.5(b)(x).

- (v) Maintenance log summaries including details on injector type and timing, setting adjustments, major engine overhauls, and routine engine tune-ups. For spot charters this shall be provided as available.
- (vi) The annual hours of operation of the survival capsules, summarized monthly.
- (f) *Pigging*. For each pig receiver and launcher, the number of pigging events per day, quarter and year.
- (g) *Tanks/Sumps/Separators*.
 - (i) On a monthly basis, the total oil emulsion and produced gas production along with the number of days per month of production.
 - (ii) For the Group A and B units, list any changes in service type and provide an explanation of the change(s) that occurred.
- (h) *Solvent Usage*. On a monthly basis: the amount of solvent used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed; whether the solvent is photochemically reactive; and, the resulting emissions of ROC and photochemically reactive solvents to the atmosphere in units of pounds per month.
- (i) *General Reporting Requirements*.
 - (i) On quarterly basis, the emissions from each permitted emission unit for each criteria pollutant in units of tons per quarter.
 - (ii) On quarterly basis, the emissions from each exempt emission unit for each criteria pollutant in units of tons per quarter. Include an annual summary of exempt equipment hours with emissions.
 - (iii) A summary of each and every occurrence of non-compliance with the provisions of this permit, District rules, and any other applicable air quality requirement.
 - (iv) The produced gas, produced oil, fuel gas, and produced wastewater process stream analyses as required by condition 9.C.13 of this permit. Process stream analyses per Section 4.12
 - (v) Breakdowns and variances reported/obtained per Regulation V along with the excess emissions that accompanied each occurrence
 - (vi) Helicopter trips (by type and trip segments with emission calculations)
 - (vii) A copy of all completed District-10 forms (*IC Engine Timing Certification Form*).
 - (viii) A copy of the Rule 202 De Minimis Log for the stationary source.

- (ix) Summary results of all compliance emission source testing performed for the stationary IC engines, central process heater and the crew and supply boats during the reporting period
- (x) The annual fuel gas analyses required per the *Process Stream Sampling and Analysis* permit condition of this permit.

[Re: PTO 9102, ATC 9634, PTO 9634, ATC 9828, ATC/PTO 10038]

C.11 **BACT.** ExxonMobil shall apply emission control and plant design measures which represent Best Available Control Technology (BACT) to the operation of Platform Heritage as described in Section 4.10 and Tables 4.1 and 4.2 of this permit. BACT measures shall be in place and in operation at all times for the life of the project. [PTO 9102, ATC 9634, PTO 9634]

C.12 **Source Testing.** The following source testing provisions shall apply:

- (a) ExxonMobil shall conduct source testing of air emissions and process parameters listed in Table 4.3 of this Permit to Operate. More frequent source testing may be required if the equipment does not comply with permitted limitations or if other compliance problems, as determined by the APCO, occur. Source testing of the crane engine and process heater shall be performed on a biennial schedule using June 1994 as the anniversary test date. The crane engine shall be loaded to the maximum safe load obtainable. Source testing of the crew and supply boat main engines shall occur on an annual basis using September of 1995 as the anniversary test date. The crew and supply boat main engines shall be tested at normal cruise speeds (minimum of 70 percent of maximum engine load). Only one crew boat and one supply boat shall be tested per year. Source testing of the cement and cuttings reinjection pumps shall be performed if triggered by Rule 333.I.8.
- (b) ExxonMobil shall submit a written source test plan to the District for approval at least thirty (30) calendar days prior to initiation of each source test. The source test plan shall be prepared consistent with the District's *Source Test Procedures Manual* (revised May 1990 and any subsequent revisions). This plan shall include a technical evaluation on how these engines will be tested at the maximum safest load. ExxonMobil shall obtain written District approval of the source test plan prior to commencement of source testing. The District shall be notified at least ten (10) calendar days prior to the start of source testing activity to arrange for a mutually agreeable source test date when District personnel may observe the test.
- (c) Source test results shall be submitted to the District within forty-five (45) calendar days following the date of source test completion and shall be consistent with the requirements approved within the source test plan. Source test results shall document ExxonMobil's compliance status with mass emission rates in Section 5 and applicable permit conditions, and rules. All District costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by ExxonMobil as provided for by District Rule 210.

- (d) A source test for an item of equipment shall be performed on the scheduled day of testing (the test day mutually agreed to) unless circumstances beyond the control of the operator prevent completion of the test on the scheduled day. Such circumstances include mechanical malfunction of the equipment to be tested, malfunction of the source test equipment, delays in source test contractor arrival and/or set-up, or unsafe conditions on site. Except in cases of an emergency, the operator shall seek and obtain District approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. Once the sample probe has been inserted into the exhaust stream of the equipment unit to be tested (or extraction of the sample has begun), the test shall proceed in accordance with the approved source test plan. In no case shall a test run be aborted except in the case of an emergency or unless approval is first obtained from the District. If the test cannot be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the District. Failing to perform the source test of an equipment item on the scheduled test day without a valid reason and without District's authorization shall constitute a violation of this permit. If a test is postponed due to an emergency, written documentation of the emergency event shall be submitted to the District by the close of the business day following the scheduled test day.
- (e) The timelines in (a), (b), and (c) above may be extended for good cause provided a written request is submitted to the District at least three days in advance of the deadline, and approval for the extension is granted by the District. [*Re: PTO 9102*]

C.13 **Process Stream Sampling and Analysis.** ExxonMobil shall sample analyze the process streams listed in Section 4.12 of this permit according to the methods and frequency detailed in that Section. All process stream samples shall be taken according to District approved ASTM methods and must follow traceable chain of custody procedures. [*Re: District Rules 325, 331, 333, PTO 9102*]

- (a) Monitoring: ExxonMobil shall analyze the process streams listed in this condition and section 4.12.
- (b) Recordkeeping: Process stream analyses data as required by this condition and section 4.12.

C.14 **Offsets - NSR.** ExxonMobil shall offset all emissions of reactive organic compounds (“ROC”) associated with the issuance of ATC 9634, ATC 9828, ATC 9099 and PTO 9012 as detailed in Section 7 and Table 7.1 of this permit. Emission reduction credits sufficient to offset the permitted quarterly ROC emissions shall be in place for the life of the project. [*Re: ATC 9634, PTO 9634, ATC 9828, ATC 9099, PTO 9102*]

C.15 **Offsets - Rule 359.** ExxonMobil shall offset all emissions of oxides of sulfur (SO_x) pursuant to Section 7 and Table 7.2 of this permit from the planned flaring of hydrocarbon gases on Platform Heritage as defined in District Rule 359. Emission reduction credits sufficient to offset the permitted quarterly SO_x emissions due to planned flaring shall be in place for the life of the project. [*Re: PTO 9102-01*]

C.16 **Process Monitoring Systems - Operation and Maintenance.** All platform process monitoring devices listed in Section 4.11.2 of this permit shall be properly operated and maintained

according to manufacturer recommended specifications. ExxonMobil shall implement the District approved *Process Monitor Calibration and Maintenance Plan* for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment, is utilized. [Re: PTO 9102]

- C.17 **Permitted Equipment.** Only those equipment items listed in Attachment 10.4 are covered by the requirements of this permit and District Rule 201.B. [Re: District Rule 1303, PTO 9102, ATC 9634, PTO 9634, ATC 9828]
- C.18 **Mass Emission Limitations.** Mass emissions for each equipment item (i.e., emissions unit) associated with Platform Heritage shall not exceed the values listed in Tables 5.3 and 5.4. Emissions for the entire facility shall not exceed the total limits listed in Table 5.5. [Re: District Rule 1303, PTO 9102, ATC 9634, PTO 9634, ATC 9828, ATC/PTO 10038, 40 CFR 70.6]
- C.19 **Facility Throughput Limitations.** Platform Heritage production shall be limited to a monthly average of 75,000 barrels of oil emulsion⁷ per day and 75 million standard cubic feet of produced gas per day. ExxonMobil shall record in a log the volumes of oil emulsion and gas produced and the actual number of days in production per month. The above limits are based on actual days of operation during the month. [Re: PTO 9102]
- C.20 **Emission Factor Revisions.** The District may update the emission factors for any calculation based on USEPA AP-42 or District P&P emission factors at the next permit modification or permit reevaluation to account for USEPA and/or District revisions to the underlying emission factors. Further, ExxonMobil shall modify its permit via an ATC application if compliance data shows that an emission factor used to develop the permit's potential to emit is lower than that documented in the field. The ATC permit shall, at a minimum, adjust the emission factor to that documented by the compliance data consistent with applicable rules, regulations and requirements. [Re: PTO 9102]
- C.21 **Abrasive Blasting Equipment.** All abrasive blasting activities performed on Platform Heritage shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530. [Re: District Rule 303, PTO 9102]
- C.22 **Produced Gas.** ExxonMobil shall direct all produced gases to the main gas compressors, the flare header or other permitted control device when de-gassing, purging or blowing down any oil and gas well or tank, vessel or container that contains reactive organic compounds or reduced sulfur compounds due to activities that include, but are not limited to, process or equipment turnarounds, process upsets (e.g., well spikes), well blow down and MMS ordered safety tests. [Re: District Rules 325, 331, PTO 9102]
- C.23 **Emergency Episode Plan.** Six months prior to each scheduled triennial operating permit reevaluation date, ExxonMobil shall review and update the Emergency Episode Plan for Platform Heritage and submit it for District approval. [Re: District Rule 1303, PTO 9102]

⁷ Oil emulsion is defined as the total amount of crude oil and water produced from the wells.

C.24 **Documents Incorporated by Reference.** The documents listed below, including any District-approved updates thereof, are incorporated herein and shall have the full force and effect of a permit condition for this operating permit. These documents shall be implemented for the life of Platform Heritage.

- (a) *Fugitive Emissions Inspection and Maintenance Program for Platforms Heritage and Harmony* (approved 3/1/1999).
- (b) *Boat Monitoring and Reporting Plan* (approved 7/2008).
- (c) *Diesel Engine Particulate Matter (PM) Operation and Maintenance Plan* (approved 5/20/1999).
- (d) *Flare Gas Sulfur Reporting Plan* (approved 12/23/1994).
- (e) *Process Monitor Calibration and Maintenance Plan* (approved 5/5/2010).
- (f) *Rule 359 Flare Minimization and Monitoring Plan* (approved 4/23/2010).
- (g) *Rule 333 IC Engine Inspection and Maintenance Plan* (approved 7/30/2009).
- (h) *Solvent Reclamation Plan* (approved 3/13/2000).
- (i) *Flare Ignition System Maintenance Plan* (approved 1/4/2002).
- (j) *Fuel Gas Sulfur Reporting Plan* (approved 11/13/1995)
- (k) *Emergency Episode Plan* (approved 1/30/1997)
- (l) *Rule 343 Purging/Degassing Plan* (approved 12/15/1994)[*Re: District Rules 317, 331, 333, 359, PTO 9102*]

C.25 **Visible Emissions**

- (a) Planned Flaring: No visible emissions shall occur from any planned flaring events. Once per calendar quarter, ExxonMobil shall perform a visible emissions inspection for a one-minute period during a planned flaring event occurring during daylight hours. If a planned flaring event does not occur during daylight hours within the calendar quarter, no monitoring is required. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. All records shall be maintained consistent with the recordkeeping condition of this permit.

- (b) Diesel Fueled IC Engines: No visible emissions shall occur from any diesel fueled engines. Once per calendar quarter, ExxonMobil shall perform a visible emissions inspection for a one-minute period on each diesel engine when operating, except for diesel engine powered vehicles on-site and diesel engines that qualify as non-road engines per the definition in 40 CFR 89.2. For the firewater pump, ExxonMobil shall perform a one-minute visible emission inspection each time the firewater pump is operated longer than 15-minutes during any testing or emergency drills (otherwise no inspection is required). The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. All records shall be maintained consistent with the recordkeeping condition of this permit.
- (c) Offshore Platform Crane: During biennial source testing of a crane, ExxonMobil shall perform a visible emissions inspection for a one-minute period on the crane. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. All records shall be maintained consistent with the recordkeeping condition of this permit.

C.26 **Gas Scrubber.** The following equipment are included in this emissions unit category:

Device Name	ExxonMobil ID	District Device No
Carbon Canister 1		114586
Carbon Canister 2		114587
Hydrogen Sulfide Scrubber		114588

- (a) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rules 310 and 325.E.1.c. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition ExxonMobil shall meet the following requirements:
- (i) The equipment listed in this permit shall be used only when there are no active production activities taking place on the platform and the flare has been taken out of service for maintenance or repair.
 - (ii) All vessels shall be depressurized to no greater than 0 psig prior to the flare being removed from service.
 - (iii) ExxonMobil shall notify the District by noon of the next business day after bringing the gas scrubber system into operation and after taking it out of operation.
 - (iv) When the flare is out of service, all vapors from the flare system shall be vented through two carbon canisters and one hydrogen sulfide scrubber connected in series.

- (v) The ROC removal efficiency across the gas scrubber system shall be greater than 90 percent (mass basis) or outlet stack ROC concentrations shall be ≤ 10 ppmv.
- (vi) The first carbon canister shall be replaced prior to breakthrough, as indicated by either:
 - (1) the ROC outlet concentration from the first carbon canister equaling (or exceeding) the inlet ROC concentration to the first canister, or
 - (2) outlet ROC concentration from the second carbon canister is greater than 10 percent of the inlet ROC concentration to the first carbon canister.

Dilution air or exhaust recirculation shall not be used in the carbon control system.

- (vii) The control system shall be leak-free, properly installed, and properly maintained at all times.
- (viii) At least two (2) back-up canisters with virgin carbon shall be maintained on site during periods when the carbon canister system is in use. Loose virgin carbon sufficient to completely refill two canisters may be used to satisfy this requirement. The back-up canister(s) shall be installed within one (1) hour after breakthrough is detected per Condition (a)(vi).
- (ix) ExxonMobil shall notify the District no later than seven days after the date of initial operations each time the carbon canister system is brought into service.

(b) Monitoring:

- (i) When the gas scrubber system is in operation, the inlet port and outlet port of each canister in the system shall be monitored twice per day. The monitoring for reactive organic compounds shall be done with an instrument which meets the requirements of EPA Method 21 and is equipped with an activated carbon filter probe adapter. Two readings shall be taken at each monitoring location: one with the filter and one without the filter. The difference between the two readings at each port is the ROC concentration at that port. The inlet and outlet readings shall be taken within 15 minutes of each other.
- (ii) If breakthrough is detected, all carbon canisters upstream of the last canister must be replaced with a backup canister using virgin carbon within one (1) hour of detection. The last canister may be used to replace one of the upstream canisters. At all times the carbon in the last canister shall be as new as, or newer than, the carbon in the upstream canisters. ExxonMobil shall be in violation of Condition 1(e) if the carbon is not replaced within one hour of detection of breakthrough as defined in Condition 1(f)(i) and Condition 1(f)(ii).
- (iii) Monitoring for hydrogen sulfide shall be done twice a day with a portable H₂S monitor or an alternative method approved by the District.

- (iv) Any new temporary fugitive hydrocarbon emitting components (valves, flanges, connections, etc.) shall be monitored on the first day of operation of the control system in accordance with the current District-approved *Fugitive Emissions Inspection and Maintenance Plan* (approved 7/15/1994). Repairs shall be made to any leaking components.
- (c) Recordkeeping: The installation date and replacement date of each canister shall be recorded, along with the cumulative hours of use of each canister. A log shall be maintained documenting the times of the daily ROC readings, portable analyzer calibration records, H₂S readings, the ppmv values and the efficiency results.
- (d) Reporting: A report containing all information required by the recordkeeping condition shall be submitted within 30 days of removing the control system from service. In addition, the report shall be included in the *Compliance Verification Report* required by this permit.

9.D District-Only Conditions

The following section lists permit conditions that are not enforceable by the USEPA or the public. However, these conditions are enforceable by the District and the State of California. These conditions are issued pursuant to District Rule 206 (*Conditional Approval of Authority to Construct or Permit to Operate*), which states that the Control Officer may issue an operating permit subject to specified conditions. Permit conditions have been determined as being necessary for this permit to ensure that operation of the facility complies with all applicable local and state air quality rules, regulations and laws. Failure to comply with any condition specified pursuant to the provisions of Rule 206 shall be a violation of that rule, this permit, as well as any applicable section of the California Health & Safety Code.

= There are no permit conditions that are District-only enforceable for this permit =

AIR POLLUTION CONTROL OFFICER

Date

Attachments:

- 1 - Emission Calculation Documentation
- 2 – Further Calculations for Section 5
- 3 - Source NEI
- 4 - Equipment List

Notes:

Reevaluation Due Date: June 2015

Semi-Annual reports are due by March 1st and September 1st of each year

\\sbcapcd.org\shares\Groups\ENGR\WP\Oil&Gas\Major Sources\SSID 01482 Exxon - SYU Project\Permits - Heritage\Reevals\Reeval PTO 9102-R5\PTO PT-70 9102 R5 - Draft Permit 4-24-2012.doc

10.0 Attachments

10.1. Emission Calculation Documentation

This attachment contains all relevant emission calculation documentation used for the emission tables in Section 5. Refer to Section 4 for the general equations. The letters A-H refer to Tables 5.1 and 5.2.

Reference A - Combustion Engines

1. The maximum operating schedule is in units of hours.
2. BSFC = 6,480 Btu/bhp-hr - East Crane
 - a. energy based value using LHV
 - b. Detroit Diesel 8V-92TA engine specification basis = 0.352 lb/bhp-hr
3. Emission factors units (lb/MMBtu) are based on HHV.
4. LCF (LHV to HHV) value of 6 percent used.
5. NO_x emission factor for crane engine based on Rule 333 limit (8.4 g/bhp-hr)

$$E_{lb/MMBtu} = \left[\frac{(8.4 \text{ g/bhp}) * 10^6}{(6480 \text{ Btu/bhp-hr}) * 1.06 * 453.6} \right]$$

6. SO_x emissions based on mass balance

$$SO_x (as SO_2) = \frac{[(\%S) * (\rho_{oil}) * 20,000]}{HHV}$$

7. Allowable sulfur content of 0.0015 wt. % consistent with CARB diesel (CCR Title 17, section 93115).
8. Crane engine operational limits: General Equation

$$Q = \frac{(BSFC) * (bhp) * (LCF) * (hours/timeperiod)}{HHV}$$

9. Firewater pumps, emergency production generator, cement pump engines, the cuttings reinjection pump engine, and survival capsule engines emission factors for NO_x, ROC, CO, and PM/PM₁₀ based on AP-42 section 3.3.

See spreadsheet for calculation results

Reference B - External Combustion (Central Process Heater)

1. The maximum operating schedule is in units of hours.
2. CO emissions based on Rule 342 limit of 400 ppmvd at 3 percent O₂. Using USEPA NSPS f-factors (corrected to District standard condition), this equates to an emission factor of 0.297 lb/MMBtu.
3. SO_x emission factor based on mass balance:

$$SO_x(asSO_2) = \frac{[(0.169) * (ppmvS)]}{HHV}$$

4. Allowable sulfur content of 30 ppmv based on ATC 5651 (11/87)
5. Emissions based on heater maximum design throughput (27.2 MMBtu/hr) * emission factor.
6. Sulfur content of the HD-5 propane: 123 ppmw. This equates to 165 ppmv S.

$$ppmvS = \left[\frac{123 lbS}{10^6 lbfuel} \right] * \left[\frac{lb - molS}{32 lbS} \right] * \left[\frac{lb fuel}{21,669 Btu} \right] * \left[\frac{379 scf}{lb - mol} \right] * \left[\frac{254 Btu}{scf fuel} \right]$$

7. Process Heater operational limits: General Equation

$$Q = \frac{(MaxHeatInput) * (hours/timeperiod)}{HHV}$$

See spreadsheet for calculation results

Reference C - Combustion Flare

1. The maximum operating schedule for the purge/pilot gas and planned continuous flaring is in units of hours.
2. The maximum operating schedule for the planned other and unplanned flaring is in units of percentage of annual usage.
3. All flaring volumes based on ExxonMobil application
4. HHV = 1300 Btu/scf for all flare and purge and pilot gas (per ExxonMobil application)
5. "Planned continuous flaring" value based on one half the minimum detection limit of the flare meter:
 - a. Flare meter: Fluid Components LT 81A mass flow detection
 - b. Minimum flow detection limit of flow element: 0.25 standard feet per second
 - c. Flare header outside: 18-inches (schedule 10)
 - d. Minimum detection limit: 1,503 scfh (3.292 MMscf/qtr, 13.166 MMscf/yr)

6. Total planned continuous flaring is assumed to be one half the flare meter minimum detection limit (752 scfh). This value includes the purge fuel gas flow rate of 145 scfh. The pilot flow rate is 300 scfh. The purge value is backed out so as to perform correct sulfur oxide calculations.
7. SO_x emissions from "planned continuous flaring": purge emissions (145 scfh) based on amine unit limit (30 ppmvd S); SO_x emissions from the remainder of "planned continuous flaring" (607 scfh) based on 20,000 ppmvd S.
8. "Planned intermittent" (other) and "unplanned flaring" volumes based on ExxonMobil application. SO_x emissions based 20,000 ppmv S.
9. Planned intermittent (other) and unplanned flaring events not calculated for short-term events per District policy
10. The same emission factors are used for all flaring scenarios, except for SO_x
11. SO_x emissions based on mass balance

$$SO_x(asSO_2) = \frac{[(0.169) * (ppmvS)]}{HHV}$$

Reference D - Fugitive Components

1. The maximum operating schedule is in units of hours.
2. The component leak path definition differs from the Rule 331 definition of a component. A typical leak path count for a valve would be equal to 4 (one valve stem, a bonnet connection and two flanges).
3. Leak path counts are provided by applicant. The total count has been verified to be accurate within 5 percent of the District's P&ID and platform review/site checks.
4. Emission factors based on the District/Tecolote Report, *Modeling of Fugitive Hydrocarbon Emissions* (1/86), Model B as documented in District Policy & Procedure 6100.061 (9/98).

Reference E - Supply Boat

1. The maximum operating schedule is in units of hours.
2. Supply boat engine data based on Rincon Marine's *Santa Cruz*.
3. Two 2,000 bhp main engines (i.e., 4,000 bhp), two 200 bhp generator engines, and one 500 bhp bow thruster engine, and one 409 bhp winch are utilized. The engine bhp from the bulk transfer generator engine is not included, but emissions must be reported against the potential to emit.

4. Main engine load factor based on District *Crew and Supply Boat* study (6/87)
5. Supply boat bow thruster engine only operates during maneuver mode
6. Supply boat generator engines provide half of total rated load of each engine at the same time.
7. The District has standardized the total time a supply boat operates (per trip) within 25 miles of platform to 11 hours. A trip includes time to, from and at the platform. This is based on a typical trip consisting of: 8 hours cruise, 2 hours maneuver and 1 hour idle.
8. Main engine emission factors are based only on cruise mode values.
9. Supply boat main engines achieve a controlled NO_x emission rate of 8.4 g/bhp-hr through the use of emission controls (e.g., turbo-charging, enhanced inter-cooling and 4° timing retard). This emission factor equates to 337 lb/1000 gallons.

$$EF_{NOx} = \frac{(8.4 \text{ g/bhp-hr}) * 1000}{(0.055 \text{ gal/bhp-hr}) * (453.6 \text{ g/lb})}$$

10. Spot charter supply boat usage limited to 10 percent of actual annual controlled supply boat usage.
11. Spot charter and Emergency Response vessels are uncontrolled for NO_x.
12. Emissions from the ExxonMobil MonArk boat are attributable to the Emergency Response emission liability category.
13. Uncontrolled ROC and CO emission factors for the spot charter main engines are based on USEPA AP-42, Volume II, Table II-3.3 (1/75) {cruise factor, 2500 bhp engine}
14. Uncontrolled NO_x emissions from spot charter supply and emergency response boat main engines based on an emission rate of 14 g/bhp-hr. This emission factor equates to 561 lb/1000 gallons:

$$EF_{NOx} = \frac{(14 \text{ g/bhp-hr}) * 1000}{(0.055 \text{ gal/bhp-hr}) * (453.6 \text{ g/lb})}$$

15. PM emission factor for the main engines are based on *Kelly, et. al.* (1981)
16. PM₁₀:PM ratio = 0.96; ROC:TOC ratio = 1.0
17. All SO_x emissions based on mass balance

$$SO_x (asSO_2) = \frac{[(\%S) * (\rho_{oil}) * 20,000]}{HHV}$$

18. Sulfur content basis of 0.0015 wt % is consistent with CARB diesel.

19. USEPA AP-42 emission factors converted to fuel basis using:

$$EF_{lb/kgal} = \frac{(EF_{lb/MMBtu}) * (19,300 Btu/lb) * (7.05 lb/gal)}{1,000}$$

20. Spot charter engine set-up assumed to be equal to main supply boat.

21. Emergency response vessel liability is based on the assumption of a *Clean Seas* vessel currently servicing the waters off of Santa Barbara

22. Emergency response vessel is permanently assigned to Platforms Henry, Hillhouse, A, B, C, Houchin, Hogan, Habitat, Hondo, Harmony, and Heritage. Vessel total bhp is 1,770 bhp. Short-term emissions from this vessel are not assessed. Long-term emissions are assessed equally amongst the eleven affected platforms.

23. Emergency response vessel emissions calculated as an aggregate (main and auxiliary engines) using the uncontrolled supply boat emission factors. The long term hours of operating are back-calculated based on the fuel usage allocation for this platform of 4,546 gallons per year (50,000 gal/yr basis).

$$T_{yr} = \frac{(4,546 gal/yr)}{[(0.055 gal/bhp-hr) * (1,770 bhp) * 0.65]} = 72 hr/yr$$

24. Main and auxiliary engine operational limits: General Equation

$$Q = (BSFC) * (bhp) * (hours/timeperiod) * (loadfactor)$$

see spreadsheet for calculated values

Reference F - Crew Boat

1. The maximum operating schedule is in units of hours.
2. Crew boat engine data based on Rincon Marine's *Callie Jean*: Four 965 bhp main engines (i.e.; 3,860 bhp), and two 131 bhp auxiliary engines.
3. *M/V Broadbill* crew boat engine data: Four 600 bhp main engines (Tier II) and two 62 bhp auxiliary engines (Tier II) subject to DOI 042-01.
4. The total permitted quarterly and annual emissions for the facility assume that the *M/V Broadbill* operates forty percent (40%) of the annual total DPV crew boat usage.
5. Main engine load factor based on District *Crew and Supply Boat* study (6/87).

6. Crew boat auxiliary engine provides half of total rated load.
7. The total time a crew boat operates (per trip) is 3.7 hours. A trip includes time to, from and at the platform. This is based on a typical trip consisting of: 1.7 hours cruise, 1 hour maneuver and 1 hour idle.
8. Crew boat main engines achieve a controlled NO_x emission rate of 8.4 g/bhp-hr through the use of turbo-charging, inter-cooling and 4° timing retard. This emission factor equates to 337 lb/1000 gallons:

$$EF_{NO_x} = \frac{(8.4 \text{ g/bhp-hr}) * 1000}{(0.055 \text{ gal/bhp-hr}) * (453.6 \text{ g/lb})}$$

9. *M/V Broadbill* main engines achieve a controlled NO_x emission rate of 5.46 g/bhp-hr through the use of DDEC electronic control systems and turbochargers. This emission factor equates to 218.98 lb/kgal.
10. Uncontrolled ROC and CO emission factors for the spot charter main engines are based on USEPA AP-42, Volume II, Table II-3.3 (1/75) {cruise factor, 900 bhp engine}
11. Uncontrolled NO_x emissions from spot charter crew boat main engines based on an emission rate of 14 g/bhp-hr. This emission factor equates to 561 lb/1000 gallons:

$$EF_{NO_x} = \frac{(14 \text{ g/bhp-hr}) * 1000}{(0.055 \text{ gal/bhp-hr}) * (453.6 \text{ g/lb})}$$

12. PM emission factor for the main engines are based on *Kelly, et. al.* (1981).
13. PM₁₀:PM ratio = 0.96; ROC:TOC ratio = 1.0.
14. Sulfur content basis of 0.0015 wt % is consistent with CARB diesel.
15. All SO_x emissions based on mass balance:

$$SO_x (asSO_2) = \frac{[(\%S) * (\rho_{oil}) * 20,000]}{HHV}$$

16. USEPA AP-42 emission factors converted to fuel basis using:

$$EF_{lb/kgal} = \frac{(EF_{lb/MMBtu}) * (19,300 \text{ Btu/lb}) * (7.05 \text{ lb/gal})}{1,000}$$

17. Main and auxiliary engine operational limits: General Equation

$$Q = (BSFC) * (bhp) * (hours/timeperiod) * (loadfactor)$$

Reference G - Pigging Equipment

1. Maximum operating schedule is in units of events.
2. Gas and oil launcher and receiver volumes, pressures and temperatures based on application.
3. All gas in launchers is blown down to the vapor recovery system or the flare relief system and purged with sweetened produced gas, nitrogen or water prior to opening the vessel to the atmosphere.
4. The remaining vessel pressure is no greater than 1 psig (15.7 psia). The temperature of the remaining vapor in both vessels = 100°F
5. The MW of purge gas = 23 lb/lb.
6. ROC weight % of purge gas = 30%
7. Calculate a site vessel specific emission factor, using the ideal gas law and the volume of the vessel, in units of "lb ROC/acf-event":

$$\rho = \left(\frac{(P_{ves} * MW)}{(R * T)} \right)$$

$$EF = \rho * ROC(wt\%)$$

Where:

ρ = the density of vapor remaining in the vessel (lb VOC/acf).

EF = Emission Factor is units of lb ROC/acf event

Reference H - Sumps/Tanks/Separators

1. Maximum operating schedule is in units of hours.
2. There are no oil/water separators on Platform Heritage.
3. Emission calculation methodology based on the CARB/KVB report *Emissions Characteristics of Crude Oil Production Operations in California* (1/83) as documented in District P&P 6100.060.
4. Calculations are based on surface area of emissions unit as supplied by the applicant.
5. All emission units are classified as secondary production and heavy oil service.
6. Controls (vapor recovery) are utilized only on the closed drain sump and the amine sump. The emission factors reflect a 95 percent control efficiency.

Reference I - Solvents

1. All solvents not used to thin surface coatings are included in this equipment category.
2. Quarterly and annual emission rates per application. Daily number is annualized.
3. Hourly emissions based on daily value divided by an average 24-hour day. Compliance with daily value based on monthly emissions divided by the number of days per month.
Compliance with hourly data to be based on the monthly daily average divided by 24.

GHG Emission Factor Basis:

Combustion Sources:

GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO₂ equivalent emission factors are calculated for CO₂, CH₄, and N₂O individually, then summed to calculate a total CO_{2e} emission factor. Annual CO_{2e} emission totals are presented in short tons.

For IC engines, the emission factor in lb/MMBtu heat input is converted to g/bhp-hr output based on a standard brake-specific fuel consumption.

For natural gas combustion the emission factor is:

(53.02 kg CO₂/MMBtu) (2.2046 lb/kg) = 116.89 lb CO₂/MMBtu
 (0.001 kg CH₄/MMBtu) (2.2046 lb/kg)(21 lb CO_{2e}/lb CH₄) = 0.046 lb CO_{2e}/MMBtu
 (0.0001 kg N₂O/MMBtu) (2.2046 lb/kg)(310 lb CO_{2e}/lb N₂O) = 0.068 lb CO_{2e}/MMBtu
 Total CO_{2e}/MMBtu = 116.89 + 0.046 + 0.068 = **117.00 lb CO_{2e}/MMBtu**

For diesel fuel combustion the emission factor is:

(73.96 kg CO₂/MMBtu) (2.2046 lb/kg) = 163.05 lb CO₂/MMBtu
 (0.003 kg CH₄/MMBtu) (2.2046 lb/kg)(21 lb CO_{2e}/lb CH₄) = 0.139 lb CO_{2e}/MMBtu
 (0.0006 kg N₂O/MMBtu) (2.2046 lb/kg)(310 lb CO_{2e}/lb N₂O) = 0.410 lb CO_{2e}/MMBtu
 Total CO_{2e}/MMBtu = 163.05 + 0.139 + 0.410 = **163.60 lb CO_{2e}/MMBtu**

Converted to g/hp-hr:

(163.60 lb/MMBtu)(453.6 g/lb)(7500 Btu/hp-hr)/1,000,000 = **556.58 g/hp-hr as CO_{2e}**

10.2. Further Calculations for Section 5

This attachment contains emission calculation spreadsheets and other supporting calculations used for the emission tables in Section 5 and permit conditions in Section 9. Refer to Section 4 for the general equations, assumptions and emission factor basis used.

Table 10.1 Variables Used in Emission Calculations

Variable	Value	Units	Reference
HHV fuel gas	1,300	Btu/scf	Exxon 1994 PTO application
HHV propane	2,524	Btu/scf	American Gas Association
HHV Diesel #2	138,200	Btu/gal	Bureau of Standards Pub. 97 " <i>Thermal Properties of Petroleum Prooducts</i> "
LCF	1.06	n/a	Chemical Engineer's Handbook, Figure 9-3, <i>Heat of Combustion of Petroleum Fuels</i> , 5th Ed
Diesel ICE PM10 Ratio	1.0	n/a	AP-42 Table 3.3-1, footnote (b), 10/96
Diesel ICE ROC Ratio	0.8378	n/a	APCD VOC/ROC Profile sheet (July 13, 1998)
Diesel Density	7.043	lb/gal	Bureau of Standards Pub. 97 " <i>Thermal Properties of Petroleum Prooducts</i> "
Process Heater ROC Ratio	0.50	n/a	APCD VOC/ROC Profile sheet (July 13, 1998)
Process Heater PH PM10 Ratio	1.0	n/a	AP-42 Table 1.4-2, footnote (c), 3/98
Flare ROC Ratio	0.86	n/a	PTO 9102
Flare PM Ratio	1.0	n/a	PTO 9102

Table 10.2 Fuel Use Limits

IC Engines	Fuel Use Limits			
	gal/hr	gal/day	gal/qtr	gal/yr
East Crane	22.4	537	24,491	97,962
B - Side Cement Pumping Skid	28.8	690	62,990	251,961
C - Side Cement Pumping Skid	28.8	690	62,990	251,961
Cuttings Reinjection Pump	25.9	621	56,691	226,765

Central Process Heater	Fuel Use Limits			
	scf/hr	scf/day	MMscf/qtr	MMscf/yr
Natural Gas Fired	20,923	502,154	45.822	183.286
Propane Fired	10,777	64,659	0.862	3.448

TABLE 10.2 - Crew and Supply Boat Fuel Use Limits
ExxonMobil Platform Heritage
Part 70 / PTO 9102 - R4

Supply Boats	Fuel Use Limits			
	gal/hr	gal/day	gal/qtr	gal/yr
Main Engines - Controlled	143.0	3,146	60,318	241,272
Generator - Uncontrolled	11.0	242	5,878	23,512
Auxiliary Engines - Bow Thruster	27.5	83	2,004	8,015
Auxiliary Engines - Winch	22.5	67	1,639	6,557
Emergency Response			1,137	4,546

Spot Charter Boats		Fuel Use Limits			
		gal/hr	gal/day	gal/qtr	gal/yr
Main Engines					
Uncontrolled Supply Boat		143	3,146	6,032	24,127

Total Supply Boats		Fuel Use Limits			
		gal/hr	gal/day	gal/qtr	gal/yr
Controlled Engines		143	3,146	60,318	241,272
Uncontrolled Engines		61	392	9,521	38,084
Spot Charter		143	3,146	6,032	24,127
Emergency Response				1,137	4,546
Total Supply Boats		347	6,684	77,008	308,029

Total Supply Boats		Hourly Limits			
		Hourly	Daily	Quarterly	Yearly
Supply Boats:					
Main Engine		1	22	422	1,687
Spot Charter Main Engine		1	22	42	169
Generator - Uncontrolled		1	22	534	2,137
Auxiliary Engines - Bow Thruster		1	3	73	291
Auxiliary Engines - Winch		1	3	73	291
Emergency Response				18	72

Crew Boats		Fuel Use Limits			
		gal/hr	gal/day	gal/qtr	gal/yr
Main Engines - Controlled		180	3,916	35,622	142,487
Auxiliary Engines		7	156	6,052	24,209

M/V Broadbill		Fuel Use Limits			
		gal/hr	gal/day	gal/qtr	gal/yr
Main Engines - Controlled		112	2,468	23,748	94,992
Auxiliary Engines - Controlled		3	75	4,035	16,139

Spot Charter Boats		Fuel Use Limits			
		gal/hr	gal/day	gal/qtr	gal/yr
Main Engines					
Uncontrolled Crew Boats		180	3,916	5,937	23,748

Total Crew Boats		Fuel Use Limits			
		gal/hr	gal/day	gal/qtr	gal/yr
Main Engines - Controlled		180	3,916	59,370	237,479
Auxiliary Engines		7	156	10,087	40,348
Spot Charter		180	3,916	5,937	23,748
Total Crew Boats		368	7,988	75,394	301,575

Total Crew Boats		Hourly Limits			
		Hourly	Daily	Quarterly	Yearly
Crew Boats:					
Main Engine		1	22	197	790
Spot Charter Main Engine		1	22	33	132
Auxiliary		1	22	840	3,360
M/V Broadbill Main Engines		1	22	212	847
M/V Broadbill Auxiliary Engines		1	22	1,183	4,733

10.3. Stationary Source NEI

Table 10.3 ExxonMobil – SYU Stationary Source Net Emissions Increase

Stationary Source Net Emissions Increase												
Facility No.	NO _x		ROC		CO		SO _x		PM		PM10	
	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
1482	1,087.08	98.89	912.61	70.23	1,144.81	90.01	249.31	44.26	289.19	47.73	237.26	38.48
3170	6.98	0.85	18.62	3.48	132.77	23.37	70.22	12.95	1.32	0.10	1.26	0.10
8009	901.42	0.00	21.10	3.77	142.83	0.44	45.21	0.00	53.36	0.00	51.23	0.00
8018	450.58	0.00	29.86	3.82	71.42	0.29	22.60	0.00	26.69	0.00	25.61	0.00
8019	450.58	0.00	43.64	6.28	71.42	0.29	22.60	0.00	26.69	0.00	25.61	0.00
Totals	2,896.64	99.74	1,025.83	87.58	1,563.25	114.40	409.94	57.21	397.25	47.83	340.97	38.58

10.4. Equipment List (Permitted and Exempt/Insignificant Equipment)

Except as described below, the permitted equipment for Platform Heritage is the same as listed in PTO 9102-R3 issued on May 23, 2006. A detailed equipment list is attached.

1. Updated the diesel used in engines and boats the facility to CARB diesel, with 0.0015 percent sulfur content.
2. Added three engines used in drilling operations to the emission calculations and equipment list. These three existing engines no longer qualify for an exemption in Rule 202.
3. Updated the fugitive hydrocarbon count to include previously de minimis components.
4. Updated to include the use of the *M/V Broadbill* as a project crew boat per PTO 11986. The *Broadbill* is equipped with new Tier 2 main and auxiliary diesel engines.

10.5. District Response to Comments